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PETROLEUM FISCAL SYSTEMS

IN CANADA

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PREFACE

This paper has been prepared to present an overview of the royalty, tax and incentive systems that apply to the exploration for, and development and production of oil, natural gas, and related substances in Canada, as of May 1, 1986. It does not purport to be an official interpretation of the statutes referred to, nor is it in any way a policy statement of the federal government.

As is the case in any summary of a complex area, it has been necessary to omit certain relevant but less important items and to simplify others for the purpose of brevity. Regardless, it is hoped that this presentation will benefit both the generalist, as a concise summary of the existing legislation, and the more technically oriented reader, as a starting point for more in-depth study.

It is intended that this paper will be updated as significant changes take place. Comments and suggestions, therefore, will be greatly appreciated. Please forward comments to:

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PREFACE

Cette publication a été conçue afin de donner un aperçu des systèmes de redevances, de taxes et d'incitation qui s'appliquent à l'exploration, au développement et à la production du pétrole, du gaz naturel et des produits concomitants, au Canada, en date du 1er mai 1986. Elle ne prétend pas être une interprétation officielle des statuts auxquels elle se réfère, ni, en aucune façon, exposer la politique du gouvernement fédéral.

Comme c'est souvent le cas dans des domaines aussi complexes, il a fallu omettre certains aspects intéressants mais d'importance moindre, ainsi qu'en simplifier d'autres pour limiter l'étendue du texte. Néanmoins, nous espérons que cette présentation saura bénéficier tant au généraliste, par le résumé précis de la législation existante, qu'au lecteur d'orientation plus technique, le texte lui servant de point de départ pour une étude plus approfondie du sujet.

Il est entendu que ce résumé sera mis à jour lorsque des changements significatifs seront apportés. Tout commentaire et toute suggestion seront grandement appréciés. S'il-vous-plaît, les faire parvenir au:

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INTRODUCTION

Responsibility for the taxation and management of non-renewable natural resources in Canada is shared between the federal and provincial governments. The division of legislative powers is set out in sections 91, 92 and 92A of the Constitution Act, 1867, as amended (formerly called the British North America Act, 1867).

Section 91 of the Constitution Act, 1867 establishes the legislative authority of the federal government. As they apply to the oil and gas industry, these powers include all matters relating to:

i) the raising of money by any mode or system of taxation;
ii) federal public property;
iii) the regulation of trade and commerce; and
iv) Indians, and lands reserved for Indians.

The legislative authority of the provincial governments is contained in sections 92 and 92A of the Constitution Act, 1867. It extends to the following matters:

i) direct taxation within the province to raise revenues for provincial purposes;
ii) the management and sale of public lands belonging to the province;
iii) the raising of money by any mode or system of taxation in respect of non-renewable natural resources and the primary production therefrom; and
iv) the exploration for, and development, conservation and management of non-renewable natural resources in the province, including the regulation of the rate of upstream oil and gas production.

Since 1973, federal and provincial royalty rates and structures, taxes and industry incentives have been subject to many revisions. Changes to the methods of assessing and administering royalties and taxes have made it difficult to comprehend the overall impact of the royalty and tax regimes on the oil and natural gas industry in Canada. This study's aim is to summarize the current legislation and regulations.

The paper is divided into four main parts. An overview is presented at the beginning of each part to acquaint the reader with the overall structure of the particular topic. The broad topics are:

I. Federal Upstream Taxes and Incentives
II. Provincial Royalties, Upstream Taxes and Incentives
III. Other Royalty and Incentive Systems
IV. Downstream Taxes

The table below lists current, major government petroleum revenue sources and gives the applicable rates in different regions of the country. Unless noted, federal taxes and incentives are applicable in all provinces and territories.

Government Revenue Sources

Name	Basic Charge	Base
Income Tax	36% federal after the 10% abatement for income earned in a province 16% Newfoundland 10% Prince Edward Island 15% Nova Scotia 15% New Brunswick 13% Quebec 15.5% Ontario 16% Manitoba 17% Saskatchewan 11% Alberta 16% British Columbia 10% Northwest Territories 10% Yukon	- levied on taxable income from all sources - deductions are allowed for exploration, development and capital expenses - Crown royalties deductible provincially but not federally - basic rate reduced for small businesses, and manufacturing and processing activities

Name	Basic Charge	Base
Petroleum and Gas Revenue Tax	eliminated for new production; being phased-out for existing production (13 1/3% generally for 1986)	- levied on income minus operating costs and, for eligible taxpayers, a resource allowance
Royalties: Provincial Lands	rates and structures vary from province to province and are, with some exceptions, dependent on price, production, discovery date, method of extraction, etc.	- on oil and gas production in a province - most provinces give relief to low productivity wells - profit-sensitivity for high-cost, non-conventional activity
Frontier Lands	1%/5%/30% (details to be worked out)	- prior to project payout, commences at rate of 1% of gross revenues and rises to 5% in increments of 1% every 18 months - after payout, equals the larger of 5% of gross revenues or 30% of net cash flow
Sales Taxes	12% federal; provincial rates vary by province	- levied on most petroleum products, including gasoline - natural gas and home heating fuels are exempt
Federal Excise Tax	3.5 cents per litre 2.0 cents per litre	- levied on gasoline and aviation gasoline - levied on diesel and jet fuel

The overview to Part II provides a somewhat more detailed provincial royalty and incentive summary table, including the nature of provincial oil and gas royalties and reductions, for each of Alberta, Saskatchewan and British Columbia.

Six appendices are also provided: a description of selected historical fiscal changes; sample tax calculations; an evaluation of alternative investment opportunities; a conversion table; a glossary of financial and fiscal acronyms in common usage in the oil and gas industry; and a brief reference guide to the enabling tax legislation.

Examples are provided throughout the paper. The numbers used in the examples are intended for illustrative purposes only.

References to enabling legislation are also included throughout the paper to facilitate in-depth study of the various fiscal provisions that are dealt with.

PART I. FEDERAL UPSTREAM TAXES AND INCENTIVES

OVERVIEW

Federal taxes and incentives applicable to the oil and gas industry in Canada are described in this part. Attention is focussed primarily on the upstream, producing sector.

The federal corporate income tax is explained in Chapter I with particular attention paid to the method of determining taxable income for corporations. Allowances for exploration, development or other expenditures are discussed. Provisions for the depreciation of capital assets are listed and commented upon. Where they differ, the income tax provisions relating to oil or gas wells are distinguished from those applicable to mineral resources such as oil sands deposits. To provide a better understanding, two ways of comparing the relative attractiveness of alternative investment possibilities are presented in Appendix III: the after-tax cost of capital and the B-index. These measures are used to focus on the relative impacts of corporate income tax provisions on different types of expenditures.

Chapter II deals with the Petroleum and Gas Revenue Tax (PGRT). This tax will be completely eliminated by 1989 as a result of provisions contained in the Western Accord which was announced on March 28, 1985. Other Western Accord changes, such as the PGRT offset, the immediate elimination of the PGRT for new production, and the $10,000 deduction, are also discussed.

Illustrative income tax and PGRT calculations are provided in Appendix II.

The federal Petroleum Incentives Program (PIP) is discussed in Chapter III. Under the provisions of the Western Accord, the PIP was eliminated on April 1, 1986. Grandfathering provisions, however, apply to certain wells in the frontier lands to the end of 1987.

CHAPTER I
FEDERAL INCOME TAXATION

A. RATES OF TAX

In effect, federal corporate income tax rates differ on income from:

i) manufacturing and processing activities versus other types of activities such as resource activities; and
ii) businesses that qualify as Canadian controlled private corporations (commonly referred to as small businesses) versus those that do not.

Resource or upstream activities in the petroleum industry include the exploration for, development and production of crude oil and natural gas, oil sands mining and heavy crude oil upgrading. Downstream activities in the petroleum industry which are subject to the manufacturing and processing tax rate include crude oil refining, natural gas processing and petrochemical manufacturing.

The basic statutory rate of federal corporate income tax is 46 percent. It is applied to taxable income (defined in section B, below) to determine a corporation's initial federal income tax liability. This liability is then reduced by 10 percent in respect of taxable income earned in a province or territory to allow for corporate income taxes levied by provincial and territorial governments. As a result, this 10 percent provincial abatement effectively reduces the rate of federal tax to 36 percent. (See Income Tax Act (ITA), sections 123 and 124.)

The federal tax rate applicable to manufacturing and processing income is effectively reduced by a further 6 percent for large corporations, in a manner similar to the provincial abatement. The federal rate is also reduced by 21 percent on qualifying small business income and, in addition, a further 5 percent for qualifying small manufacturing and processing corporations. (See ITA, subsections 125(1) and 125.1(1).) Federal tax rates are to be

phased-down over the next three years according to the following schedule:

Phase-Down of Federal Rates

	General		Small Businesses	
	Manufacturing	Other	Manufacturing	Other
	(%)			
Current	30	36	10	15
July 1, 1987	28	35	8	14
July 1, 1988	27	34	8	13
July 1, 1989	26	33	8	13

Federal tax payable by firms that do not qualify for the small business deduction is subject to a surtax of 5 percent over the period July 1, 1985, to December 31, 1986. (See ITA, section 123.1.) This results in an adjusted federal tax rate for most companies in the upstream petroleum industry equal to 37.8 percent in 1986. A 3 percent surtax, applicable to all corporations, is to be introduced on January 1, 1987.

A summary of federal corporate income tax rates for 1986, which includes the corporate surtax, is provided below.

Federal Corporate Income Tax Rates: 1986

	General		Small Businesses	
	Manufacturing	Other	Manufacturing	Other
	(%)			
Basic Statutory Rate	46	46	46	46
Less: Provincial Abatement	10	10	10	10
Small Business Deduction	-	-	21	21
Manufacturing and Processing Deduction	6	-	5	-
= Federal Rate Before Surtax	30.0	36.0	10	15
Plus: 5% Corporate Surtax	1.5	1.8	-	-
= Adjusted Federal Rate	31.5	37.8	10	15

B. NET RESOURCE INCOME

Federal income tax deductions, tax rate reductions and tax credits vary depending on the type of activity a taxpayer is engaged in. Taxpayers are, therefore, required to allocate their income by source for income tax purposes. Sources of income in the petroleum industry include upstream oil and gas activities, oil refining and natural gas processing activities, and pipeline transmission activities.

The gross income from each activity is reduced by operating costs, depreciation allowances and various other activity-related write-offs to determine net income from a source. The summation of these net income streams yields net income for tax purposes. Taxable income is derived by deducting taxable dividends, charitable donations and prior years' losses.

As noted above, the basic statutory rate of federal corporate income tax is applied to taxable income to calculate federal taxes otherwise payable. The provincial abatement, and the manufacturing and processing and small business deductions, if applicable, are then taken into account. Finally, federal tax credits (discussed in section C, below) are deducted from federal tax otherwise payable to arrive at a corporation's federal tax liability.

The total proceeds from oil and gas production revenue and non-Crown royalty income (defined in subsection 3, below) minus certain specified deductions yields net resource income. Net resource income is, in general, determined in the following manner:

Gross Resource Income

Less: i) direct operating costs;
ii) production royalties paid or payable;
iii) general and administrative expenses;
iv) capital cost allowances; and
v) Canadian exploration and development overhead expense

= Resource Profits for Resource Allowance

Less: vi) resource allowance

Plus: vii) Canadian exploration and development overhead expense; and

viii) resource royalties received or receivable

Less: ix) resource royalties paid or payable;

x) interest expense;

xi) Canadian oil and gas property expense;

xii) Canadian development expense; and

xiii) Canadian exploration expense

= Resource Profits for Earned Depletion

Less: xiv) earned depletion, to a maximum of 25 percent of resource profits for earned depletion

= Net Resource Income.

1. Gross Resource Income

Gross resource income is the total proceeds received by a producer from the sale of oil or gas without deducting Crown royalty payments and including any production royalty income (defined in subsection 3, below). Where the producer must sell the production to a Crown agency (as was the case with most natural gas in British Columbia), however, the deemed fair market value is used for the federal income tax calculation.

2. Capital Cost Allowances

Expenditures on tangible assets are grouped into pools or classes for income tax purposes. The class of an asset determines the rate at which it may be depreciated or written-off for tax purposes. In cases where the owner of an asset receives government assistance related to its purchase, the capital cost of the asset is reduced by the amount of the assistance and, therefore, the capital cost

allowance (CCA) will be less in each year. Government assistance includes PIP grants for tertiary oil recovery equipment, and investment tax credits. For assets acquired after November 12, 1981, the taxpayer may only claim one-half of the normal CCA rate in the tax year of acquisition. (See ITA, paragraph 20(1)(a), Income Tax Regulations (ITR) 1100 to 1106, and Schedule II to the ITR.)

A sample of tangible asset classes and CCA rates, applicable to the oil and gas industry follow:

Class	Description of Capital Property	CCA Rate[1]
2(b)	- pipeline with life expectancy greater than 15 years	6% d.b.
6(e)	- refined oil storage tanks	10% d.b.
7(c)	- offshore drilling vessels	30% d.b.[2]
8(i)	- pipeline with life expectancy less than 15 years	20% d.b.
10(j)	- gas or oil well equipment[3]	30% d.b.
10(k),(l),(m)	- post development, oil sands mining assets	30% d.b.
10(u)	- heavy crude oil upgrading assets	30% d.b.
12(q)	- post development, oil sands overburden removal costs[4]	100%
28	- pre-production, oil sands mining assets and post development assets for a major, mine expansion	30% d.b.
29	- oil refining and natural gas processing assets	50% s.l.

Notes:
1. d.b. denotes declining balance; s.l. denotes straight line.
2. Rate for Class 7(c) vessels is actually 15 percent on a declining balance basis. Offshore drilling vessels are entitled to an additional 15 percent on a declining balance basis by virtue of ITR 1100(1)(va) and 1101(2b).
3. Defined in ITR 1104(2). (Definition includes a gas pipeline to a natural gas processing plant.)
4. Defined in ITR 1104(2).

3. Royalty Non-Deductibility and the Resource Allowance

Crown royalties are not deductible from income; neither are freehold mineral nor production taxes. There are four exceptions: royalties paid to Indian bands; royalties paid to Petro-Canada; joint venture payments made by the Syncrude participants to the Alberta Government; and royalties paid by a producer who purchases a lease from a Crown corporation and agrees to pay a production royalty to the corporation or to the Crown. (See ITA, paragraphs 12(1)(o) and 18(1)(m), and ITR 1211, 1204(4) and 1204(5).) One historical anomaly exists in the province of Saskatchewan whereby net royalties paid to the Crown are deductible as Canadian oil and gas property expense (defined in subsection 4, below) since these royalties were negotiated in lieu of lease payments.

The general non-deductibility of Crown royalties is compensated for by a resource allowance equal to 25 percent of gross resource income minus operating and overhead costs, production royalty payments, capital cost allowances and Canadian exploration and development overhead expense (excluding financing costs). This allowance may be claimed on the portion of income received by taxpayers on which they have been disallowed a royalty deduction as described above. (See ITA, section 20(1)(v.1), and ITR 1210.)

A non-Crown royalty with respect to the production of oil or gas may constitute either a resource royalty or a production royalty. In general, the main difference between the two types of non-Crown royalties lies in whether or not the recipient is legally responsible for a share of the Crown royalty payments. If the recipient is legally responsible for a share of Crown royalties, the non-Crown royalty is defined as a production royalty; if not, it is defined as a resource royalty.

In a situation where there is a production royalty, both the working interest and the royalty interest are responsible for their share of the Crown royalty and both, therefore, receive the resource allowance. Production royalty payments are deducted in calculating the taxable income of the working interest and are not included in

the calculation of his resource allowance. The production royalty recipient receives the resource allowance on the production royalty income.

In a situation where there is a resource royalty, on the other hand, it is generally only the working interest holders who will receive the resource allowance. Resource royalty payments are deducted in calculating the taxable income of the working interest but are included in the calculation of the resource allowance. The resource allowance is not available to the recipient of the resource royalty. The exception to this general rule applies to resource royalties in respect of oil sands mining. In this case, the royalty interest holder, instead of the working interest, receives the resource allowance on the resource royalty income.

As noted above, participants in the Syncrude Project are allowed to deduct all joint venture "royalties" paid to the Crown in computing their taxable income. In addition, they may claim the 25 percent resource allowance on revenue net of these royalties. (See Order in Council P.C. 1976-1026.)

4. Land Acquisition and Lease Maintenance Costs

The costs of acquiring an oil or gas property (commonly referred to as land bonus payments) are classified as Canadian oil and gas property expense (COGPE). As noted above, net royalty payments to Saskatchewan are also included as COGPE since they were negotiated in lieu of land bonus payments. COGPE may be written off at 10 percent per year on a declining balance basis. (See ITA, clause 66.4(5)(a)(i).)

COGPE does not, however, include land rental payments to the Crown to maintain rights to an oil or gas property, once acquired. Land rental payments in respect of a producing property are not deductible in calculating net resource income. Rental payments in respect of a non-producing property, on the other hand, are fully deductible to a maximum of $2.50 per hectare. (See ITR 1211(d).)

The costs of acquiring a mineral resource property are included as Canadian development expense and may be written off at 30 percent per year on a declining balance basis. (See ITA, clause 66.2(5)(a)(iii).)

Land rental payments in respect of a mineral resource property are neither included as Canadian development expense nor deductible in the calculation of net resource income if they relate to a commercially producing property. Rental payments made prior to the commencement of commercial production from a mineral resource property are, however, fully deductible. (See ITR 1211(b).)

5. Exploration and Development Expenses

Costs of exploration and development may be classified as either Canadian exploration expense, Canadian development expense or Canadian exploration and development overhead expense.

a) Canadian Exploration Expense

The Canadian exploration expense (CEE) definition is scheduled to be modified, effective April 1, 1987. Currently, CEE includes the costs of all geological, geochemical and geophysical activity leading up to, and including, the drilling and completing of the discovery well in a particular field. A well drilled after discovery may qualify as CEE if it satisfies one of the two following criteria:

i) it is abandoned; or
ii) it is spudded before April 1, 1987, it is completed within six months after the end of the taxation year, and it is expected not to come into production within twelve months of its completion.

The latter criterion contains the so-called "capped-well" provisions. Wells not satisfying all three of these conditions will be classified as development wells. (See ITA, clauses 66.1(6)(a)(i) and (ii).)

While the treatment of geological, geochemical and geophysical expenses will remain unchanged under the proposed new definition, an expense in respect of a well is to qualify as CEE after March 31, 1987, if:

i) the well results in the discovery of a new accumulation of oil or natural gas;
ii) the well is abandoned, without having produced commercially, within 24 months of the completion of its drilling; or
iii) the well has not produced commercially within 24 months of the completion of its drilling.

In general, an expense which does not satisfy one of these conditions within six months after the end of the taxation year in which the expense is incurred, will initially be classified as a Canadian development expense. If one of the conditions is subsequently satisfied, the expense will be reclassified as CEE at that time. Wells costing in excess of $5 million that are expected to satisfy condition (iii), however, will receive exploration treatment from the outset. Intangible capital costs incurred on a well after a period of 24 months has elapsed from the completion of its drilling, will be classified as Canadian development expense. Qualifying exploration expenses incurred in respect of a well will include the costs of drilling or completing an oil or gas well, building a temporary access road to the well, and site preparation costs. (See Department of Finance Canada, Release 86-63, "Definition of Canadian Exploration Expense" and Release 85-228 "Definition of Canadian Exploration Expense to be Changed".)

CEE also includes both exploration and development expenses incurred in respect of oil sands mining. These expenses include prospecting, geological, geochemical and geophysical surveys, preliminary sampling and overburden removal costs incurred prior to the commencement of commercial production. (See ITA, clauses 66.1(6)(a)(iii) and (iii.1).)

CEE may be fully written off in the year incurred for non-principal business corporations. For principal business corporations, the deduction is compulsory to the extent of income after deductions for direct operating costs, general and administrative expenses, capital cost allowances, the resource allowance, interest, COGPE and Canadian development expense but before taxable dividends. A principal business corporation (see ITA, paragraph 66(15)(h)) includes a corporation whose principal business is oil and gas production, refining, marketing or exploration, or operating an oil or gas pipeline. (See ITA, subsections 66.1(2) and (3).)

b) Canadian Development Expense

Canadian development expense (CDE) includes the cost of any oil or gas well which is not a Canadian exploration expense. CDE typically includes delineation well costs incurred on provincial lands and the costs of all development wells other than capped wells as discussed above. Specific examples of development wells are:

i) recompleted wells;
ii) waste disposal wells;
iii) injector wells; and
iv) wells drilled to find water or gas for injection purposes. (See ITA, clause 66.2(5)(a)(i) and (i.1).)

CDE may be written off on a declining balance basis at a 30 percent rate. (See ITA, subsection 66.2(2).)

c) Canadian Exploration and Development Overhead Expense

Overhead costs associated with exploration and development may be grouped as Canadian exploration and development overhead expense (CEDOE). Expenses that may be included in CEDOE are:

i) administrative, management or financing costs;
ii) salaries and related benefits to employees who are not entirely involved in Canadian exploration or development activities; and

iii) expenses, such as maintenance and leasing costs, taxes, and insurance premiums, relating to property that is not directly attributable to Canadian exploration and development activities. (See ITR 1206(1).)

CEDOE (net of financing costs) is fully deductible in the year incurred in the calculation of the resource allowance. It is then added back and subsequently written off as CEE or CDE, as the case may be. CEDOE that is subsequently deducted as CEE (as defined in ITA, clause 66.1(6)(a)(iii)) in respect of oil sands mining is, however, excluded from resource profits for the earned depletion allowance (see below).

6. Earned Depletion Allowance

The earned depletion allowance is an additional tax deduction which applies to certain qualifying development and capital expenditures incurred by corporations in the petroleum industry. Qualifying expenditures include CDE incurred in respect of a qualified tertiary oil recovery project, Class 10(j) well-equipment assets used in a qualified tertiary oil recovery project, Class 10(u) assets used in the upgrading of heavy crude oil to a stage which is not beyond the crude oil stage, Class 10(k) oil sands processing assets and Class 28 oil sands assets. In order to qualify for the earned depletion allowance, investments in tertiary oil recovery must be incurred while a project either is or will be, in the subsequent taxation year, subject to an approved provincial royalty system, or on a project located either on a reserve defined under the Indian Act or in the province of Ontario.

Depletion is earned on these qualifying expenditures at the rate of 33 1/3 percent and is claimable to an annual maximum of 25 percent of resource profits for earned depletion purposes. Resource profits for earned depletion equal resource profits after the resource allowance plus CEDOE and resource royalty income minus resource royalty payments, interest, COGPE, CDE and CEE.

Corporations and individuals who incur exploration and development expenditures in oil sands mining are also eligible to earn depletion on those expenditures at the rate of 33 1/3 percent. Depletion earned on oil sands exploration expenses incurred after April 19, 1983, however, may be claimed to a maximum of 25 percent of income from any source. The depletion deduction for oil sands development expenses and pre-April 20, 1983, oil sands exploration expenses is limited to 25 percent of resource profits for earned depletion.

Depletion effectively increases the cost base of an asset such that 133 1/3 percent can be deducted: 33 1/3 percent through depletion, and 100 percent through the capital cost allowance or the CDE deduction, over the life of the asset, as the case may be. (See ITA, section 65, and ITR 1200 to 1206.)

7. Flow-Through Shares

It is possible for taxpayers to deduct CEE, CDE and COGPE that are incurred on their behalf and for which they have received equity shares. In addition, corporations may deduct depletion related to CDE incurred on their behalf in respect of a prescribed tertiary oil recovery project and for which they have received equity shares. These provisions are known as the flow-through share provisions. (See ITA, clauses 66.1(6)(a)(v), 66.2(5)(a)(v) and 66.4(5)(a)(iii), and ITR 1205(1).)

Effective March 1, 1986, investors in flow-through shares need no longer incur the expenditures themselves in order to claim the associated deduction. Principal business corporations will be allowed to renounce their own expenditures to flow-through shareholders up to the amount received for the shares. In order to qualify, expenditures will have to be incurred within one year after a flow-through share agreement is entered into.

Flow-through shareholders will also earn the exploration tax credit (discussed in subsection C.3, below) in respect of their qualifying exploration expenditures.

Commencing in 1986, mining exploration expenditures (other than oil sands mining expenditures) incurred in January and February of any year by a taxpayer under a flow-through share agreement may be claimed as a deduction for the preceding taxation year.

8. Carry Over of Deductions

All of the deductions from tax in respect of expenditures which are pooled, i.e., CCA, COGPE, CDE, CEE and depletion are allowed deductions. Except for CEE incurred by principal business corporations, a taxpayer is not obliged to take the maximum deduction in the year in which the expenditure is incurred but, rather, can carry these forward indefinitely. Principal business corporations must deduct their exploration expenses as fast as net income will allow. Any excess, however, can be carried forward indefinitely.

Alternatively, unused CEE and CDE deductions may be used to reduce a taxpayer's Petroleum and Gas Revenue Tax (PGRT) liability through the PGRT offset. (See Chapter II, section E for a discussion of the PGRT offset.)

Operating losses may be carried back three years and forward seven years. (See ITA, paragraph 111(1)(a).)

C. TAX CREDITS

1. Investment Tax Credit

Capital expenditures on certain qualifying tangible assets are currently eligible for an investment tax credit of 7, 10, 20, 50 or 60 percent of the cost of their expenditure after deducting any provincial grants or PIP incentives. The rate depends on the area in Canada in which the expenditure occurs and the nature of the expenditure in each area. The areas are defined in the Regional Development Incentives Act (RDIA). Credit rates are to be modified in the following manner over the next three years:

Investment Tax Credit Rates by Region: 1986-89

(%)

	1986	1987	1988	1989
General Rate	7	5	3	0
RDIA Designated Regions[1]	10	7	3	0
Atlantic Region[2]	20	20	20	20
Special M&P Rate[3]	50	40	40	40
Cape Breton Island	60	60	60	60

Notes:
1. Includes Saskatchewan, the Northwest Territories, the Yukon and northern British Columbia and Alberta.
2. Effective February 26, 1986, the Atlantic Region includes the associated offshore area.
3. Includes buildings and equipment for use in manufacturing and processing in northern Canada and certain areas of the Atlantic provinces, other than an initial processing operation in a resource-based industry.

The tax credit may be applied to reduce a taxpayer's federal taxes otherwise payable without limitation. The amount of the credit claimed reduces the capital cost of the asset thereby reducing the amount of CCA and depletion that would otherwise be claimable.

Investment tax credits earned may be claimed in the year in which the expenditure is incurred or may, in general, be either carried back three years or carried forward seven years. The carry-forward period for Cape Breton tax credits is ten years.

A portion of the investment tax credit earned on investments made between April 20, 1983, and December 31, 1988, may be refunded directly in cash to taxpayers who can not otherwise fully use their credit to reduce their federal tax. For small business corporations and unincorporated businesses, the refund is 40 percent of the unused credit earned in a year. For large corporations, the refundable portion is 20 percent of unused investment tax credits except for unused Cape Breton tax credits which are refundable at a

40 percent rate between May 24, 1985, to December 31, 1988. That portion of the investment tax credit earned in a year that is not refunded remains available to reduce federal taxes in other taxation years subject to the provisions noted above. (See ITA, subsections 127(5) to (12.2), and ITR 4600 to 4602.)

2. Share-Purchase Tax Credit

The share-purchase tax credit (SPTC) permits both private and public corporations to use tax credits earned on new investments to attract purchasers of new common equity issued by the company between July 1, 1983, and December 31, 1986. Under the measure, corporations are allowed to issue shares which entitle the first purchaser to a tax credit of up to 25 percent of the issue price paid. Credits claimed by share purchasers reduce the amount of the investment tax credit that a corporation has available to reduce its own tax liability. Only investment tax credits earned by the corporation after April 19, 1983, are eligible to be transferred to purchasers of new equity. The measure allows corporations to issue qualifying equity in advance of undertaking investments.

Taxpayers may use the SPTC to reduce their federal tax. The credit is refundable for certain tax-exempt entities such as pension plans, which would otherwise not be able to make use of it. The SPTC reduces the tax cost of shares for the purpose of computing subsequent capital gains and losses. (See ITA, section 127.2.)

3. Exploration Tax Credit

Qualifying CEE incurred in respect of well costs in excess of $5 million per well will be eligible for the exploration tax credit (ETC). The ETC will be available over the period December 1, 1985, to December 31, 1990. The rate of the tax credit will be 25 percent. Qualifying CEE will include expenses described in clause 66.1(6)(a)(ii) of the ITA other than CEE that is not well-specific, CEDOE, financing charges, and expenses that attract an incentive under the Petroleum Incentives Program (PIP) and the Alberta

Petroleum Incentives Program (APIP). (See Chapter III and Chapter IV, subsection E.1 for a discussion of PIP and APIP, respectively.)

While the commencement date for earning the credit is December 1, 1985, certain expenses that are incurred by all taxpayers in respect of a well after March 31, 1985, will be taken into account in determining when the $5 million threshold is reached. Where more than one taxpayer incurs expenses pertaining to a well, participants will be allowed to allocate the expenses in a reasonable manner.

Taxpayers will be allowed to apply for a refund of up to 40 percent of that portion of the ETC not otherwise utilized in the year the credit is earned. Any unclaimed balance that is not refunded will be available to be used in other years in accordance with the existing investment tax credit rules.

As noted above, flow-through shareholders will earn the credit in respect of qualifying expenses incurred either by them or on their behalf.

The ETC claimed or refunded will reduce the amount of CEE that would otherwise be claimable, in a manner similar to the reduction by the investment tax credit of the capital cost of an asset for capital cost allowance purposes. Accordingly, CEE available to be used to offset PGRT otherwise payable will be reduced by the ETC that has been claimed or refunded (see Chapter II, section E for a discussion of the PGRT offset). (See Government of Canada, News Release 85/160(b), "The Exploration Tax Credit".)

CHAPTER II
PETROLEUM AND GAS REVENUE TAX

The Petroleum and Gas Revenue Tax (PGRT) is a tax on production and royalty income from crude oil and natural gas. For crude oil, the point of valuation is the wellhead. For natural gas, a price equivalent to the wellhead price for oil is determined by:

i) deducting from the price received for the gas at the processing plant, the average cost of processing and transportation from the field to the gas plant;
ii) adding the average value of products separated at the processing stage; and
iii) adding any revenues from the export flowback. (See PGRT Act, subsection 82(1) and section 83.)

Deductions are permitted for direct field operating costs, operating overhead charges, non-Crown royalty payments, and Canadian exploration and development overhead expenses (excluding financing charges). Deduction of the costs of injected substances is mandatory. While a deduction is not allowed for Crown royalties, a resource allowance is provided to working interests and production royalty interests in lieu of royalty deductibility. (Unlike the treatment under the Income Tax Act, the resource allowance in the PGRT calculation is not available to recipients of resource royalty income from oil sands deposits.) Deductions are also not permitted for interest charges and costs of a capital nature other than certain capital costs incurred in tertiary oil recovery projects (discussed in section C, below). The PGRT is not deductible for income tax purposes.

A. RATES OF TAX

Two statutory rates of PGRT exist: a general rate and a rate for synthetic oil production. The general statutory rate for 1986 is 13 1/3 percent. Since revenues subject to the general statutory rate are reduced by a 25 percent resource allowance on net operating revenue, the effective rate is 10 percent.

The statutory rate for synthetic oil was 12 percent for the period January 1, 1986, to April 30, 1986. This rate was reduced by a 50 percent resource allowance on net operating revenue for a 6 percent effective rate. From May 1, 1986, to December 31, 1986, the rate for synthetic oil will be reduced to zero. (See Energy, Mines and Resources Canada, News Release 86/73, "Federal Government to Provide Tax Relief to Canadian Petroleum Industry".)

Both the general and synthetic PGRT rates will be phased out by 1989 according to the following schedule (see PGRT Act, section 84, and PGRT Regulations, section 5.1):

Phase-Out of PGRT Rates

	General Rate (%)		Synthetic Rate (%)	
	Statutory	Effective	Statutory	Effective
1986	13 1/3	10	12/0	6/0
1987	10 2/3	8	8	4
1988	8	6	4	2
1989	0	0	0	0

B. EXEMPT PRODUCTION

Hydrocarbons that are produced by a taxpayer and also consumed by that taxpayer in the production process are exempt from PGRT (see PGRT Act, subsection 82(2), and PGRT Regulations, section 5). Also exempt is:

i) any new production of oil, natural gas and natural gas liquids from wells drilled or deepened after March 31, 1985;

ii) any oil or natural gas that is produced by, consumed by, or transported by approved major new energy projects which commenced operation after March 31, 1985; and

iii) the incremental production from new waterflood projects, major expansions to existing waterflood projects, and tertiary oil recovery projects. (See Energy, Mines and Resources Canada, Petroleum Resources Branch, Information Letter 85-01, "Interim Certification Guidelines for the New Production PGRT Exemption".)

Participants in waterflood projects which commenced operation after March 31, 1985, will be allowed to exempt from PGRT, their share of either the incremental production from the project, provided the working interests in the project agree to this treatment, or the production from new wells located in the project. Major expansions to existing waterflood projects will be treated in a similar manner. In order to elect the incremental production exemption, however, production from the expansion must be treated as new oil for royalty purposes.

A tertiary oil recovery project is a project which utilizes a recovery method that increases the remaining recoverable reserves of crude oil in a pool more than would a primary or secondary (waterflood or equivalent) recovery method. Tertiary recovery methods include thermal processes such as in-situ combustion and steam injection, chemical processes such as polymer or caustic flooding, and miscible and immiscible displacement processes such as carbon dioxide or hydrocarbon flooding.

Participants in tertiary oil recovery projects which commenced operation after December 31, 1982, and qualify for PGRT capital deductibility (see below), will be allowed to elect, subject to the unanimous agreement of the working interests in the project, to exempt from PGRT the incremental production from the project. If the election is not made, participants in qualifying projects must continue with the PGRT regime of capital deductibility. The exemption will apply to incremental production, commencing on the later of April 1, 1985, and the date of first injection. Where the election is made to exempt incremental production, Revenue Canada will reassess all project participants who had previously claimed the PGRT capital deduction.

C. TERTIARY OIL RECOVERY CAPITAL DEDUCTIBILITY

The PGRT capital deduction applies to tertiary oil recovery projects which commenced operation before January 1, 1983. It also applies to tertiary oil recovery projects which commenced operation after December 31, 1982, where the working interests in the project have not unanimously agreed to the incremental production exemption

outlined above. The PGRT on production income from the reservoir in which such a project is located will not become payable until eligible capital expenditures on the project have been recovered, by the participant, from reservoir production revenue. Taxpayers must claim the capital deduction to the full extent of their share of production income from the reservoir in which the tertiary oil recovery project is located. The PGRT relief will be delivered at the working interest level, based on eligible capital investments net of government assistance. (See PGRT Act, subsection 82(8).)

Eligible investments are restricted to those expenditures incurred after December 31, 1982, in respect of a tertiary oil recovery project. They include exploration and development expenses related to the drilling of wells required for the project, and oil and gas well equipment used in the project. These costs are typically included for income tax purposes as Canadian exploration expense, Canadian development expense and Class 10(j) assets. To be eligible, investments must be incurred while a project either is or will be, in the subsequent taxation year, subject to an approved provincial royalty system, or on a project located either on a reserve defined under the Indian Act or in the province of Ontario. (See PGRT Act, section 82.1, and August 1983 Draft Amendments to the PGRT Act and PGRT Regulations.)

D. SMALL PRODUCERS' CREDIT AND $10,000 DEDUCTION

A small producers' PGRT credit is available to corporations to reduce their PGRT otherwise payable on production income. When it was introduced on June 1, 1982, the maximum level of the credit was $250,000. For the period January 1, 1985, to April 30, 1986, it equalled $500,000. Effective May 1, 1986, it will increase to $2 million. This credit is not available to individuals in receipt of production income, or to resource or production royalty interests held by either individuals or corporations. (See PGRT Act, section 84.1 and Energy, Mines and Resources Canada, News Release 86/73, "Federal Government to Provide Tax Relief to Canadian Petroleum Industry".)

Individuals who are ineligible for the small producers' PGRT credit are, however, allowed a $10,000 deduction in calculating their production and royalty income for PGRT purposes, effective January 1, 1986. The $10,000 deduction will also be available to reduce a corporation's production and royalty income provided the corporation does not claim the small producers' credit.

E. OFFSETS

Companies that are not in an income-taxpaying position are able to use exploration and development expenditures incurred after March 31, 1985, to reduce their PGRT liability. Eligible Canadian exploration expense and Canadian development expense which are not immediately usable for federal corporate income tax purposes, are available for write-off, at current income tax rates, for purposes of the PGRT offset provisions. The offsets are allowed to reduce PGRT, at a 30 percent rate, to a maximum of PGRT otherwise payable. (See PGRT Act, subsection 84.1(7), and ITA, subsections 66(14.1) and (14.2), and 66.5(2).)

When the company eventually becomes taxable for income tax purposes, these offsets will be "repaid" to the federal government as the company is able to take advantage of the normal CEE and CDE income tax write-offs. (See ITA, section 196 and subsection 66.5(1).) The offset provisions effectively advance, in time, the ability of corporations to take advantage of income tax write-offs. (See Government of Canada, News Release 85/58, "Additional Information Provided on Measures to Offset PGRT".)

CHAPTER III
PETROLEUM INCENTIVES PROGRAM

As announced in the Western Accord, the Petroleum Incentives Program (PIP) was terminated on March 31, 1986. Grandfathering provisions, however, allow eligible exploration expenditures incurred on wells drilled in the frontier lands in order to satisfy commitments related to Exploration Agreements in effect on March 28, 1985, to continue to qualify for PIP grants until December 31, 1987.

The size of the incentive payment under the PIP depends on the Canadian ownership rate and control status (COR/CS) of the investor, the type of investment made and the geographic location of the investment. In general, the definitions/regulations used in the PIP legislation are similar to those contained in the Income Tax Act. Any expenditures deducted against income tax must also be reduced by incentive payments received. (See the Petroleum Incentives Program Act and Regulations.)

The tables below give the minimum COR/CS rates, and the corresponding incentive payment percentages, by geographical location and type of expenditure, over the life of the program.

Petroleum Incentives Program
Degree of Canadian Ownership
(%)

Year Starting January 1		Range 1	Range 2	Range 3	Range 4
1981	up to	50	50 +	60 +	65 +
1982	" "	50	50 +	61 +	67 +
1983	" "	50	50 +	62 +	69 +
1984	" "	50	50 +	63 +	71 +
1985	" "	50	50 +	64 +	73 +
1986	" "	50	50 +	65 +	75 +
1987	" "	50	50 +	65 +	75 +

Rates of Incentive Payments for Eligible Oil and Gas Expenditures by Region

(%)

	Provincial Lands				Canada Lands			
	Range				Range			
Exploration	1	2	3	4	1	2	3	4
1981	nil	nil	25	35	25	35	65	80
1982	nil	10	25	35	25	45	65	80
1983	nil	10	25	35	25	45	65	80
1984	nil	15	25	35	25	50	65	80
1985	nil	15	25	35	25	50	65	80
1986	nil	15	25	35	25	50	65	80
1987	N/A	N/A	N/A	N/A	25	50	65	80
Development								
1981	nil	nil	15	20	nil	nil	15	20
1982	nil	10	15	20	nil	10	15	20
1983	nil	10	15	20	nil	10	15	20
1984	nil	10	15	20	nil	10	15	20
1985	nil	10	15	20	nil	10	15	20
1986	nil	10	15	20	nil	10	15	20
Non-Conventional (i.e., class 10(j))								
1981	nil	nil	15	20	nil	nil	15	20
1982	nil	10	15	20	nil	10	15	20
1983	nil	10	15	20	nil	10	15	20
1984	nil	10	15	20	nil	10	15	20
1985	nil	10	15	20	nil	10	15	20
1986	nil	10	15	20	nil	10	15	20

Note: 1. PIP was terminated on March 31, 1986. Grandfathering provisions allow eligible Canada Lands exploration expenditures to continue to receive PIP until December 31, 1987.

Expenses incurred either in respect of an Exploration Agreement which commenced after March 28, 1985, or after the expiration of the primary term of an Exploration Agreement which commenced before March 29, 1985, are not, in general, eligible for PIP. Further, well expenses cease to be eligible for PIP after March 31, 1986, unless the well is grandfathered.

Grandfathered wells for PIP purposes over the period April 1, 1986, to December 31, 1987, include the following Canada Lands wells:

i) Exploration Agreement validating wells;
ii) farmout commitment wells; and
iii) farmout wide-earning option wells.

Effective April 1, 1986, only direct well expenses, i.e., site-specific field expenses, on grandfathered wells are eligible for PIP. The only geological, geophysical and geochemical expenses which are eligible during the grandfathering period are those expenses incurred in the course of and incidental to the drilling of a well which is a grandfathered well. Blowout and control of well expenses ceased to be eligible for PIP, effective April 1, 1986. Insurance premiums related to a grandfathered well, however, continue to qualify as an eligible well expense during the grandfathering period.

In addition, the only persons who can qualify to receive PIP on grandfathered wells are persons who, on March 28, 1985, are either Exploration Agreement holders (to the extent of their working interest as of March 28, 1985), or farmees to a farmout wide-earning option well agreement or a farmout commitment agreement (to the extent of their cost share under the farmout agreement).

The Petroleum Incentives Program is administered by the Petroleum Incentives Administration except in Alberta where it is administered by the Alberta government. In all cases, the definition of eligible costs is adjusted downward to take into account the extent to which the expenditures fail to give the applicant an interest in the oil or gas property commensurate with his expenditures.

PART II. PROVINCIAL ROYALTIES, UPSTREAM TAXES AND INCENTIVES

OVERVIEW

Detailed descriptions of the fiscal systems operating in Alberta, Saskatchewan and British Columbia are presented in this part. Royalty structures as they apply to various types of oil, gas and related products are discussed in detail, and examples are provided. Provincial incentives designed to stimulate exploration, development and production are reviewed. Shorter discussions of the fiscal regimes in Manitoba, Newfoundland, Nova Scotia, Ontario and Quebec are also included.

The table below summarizes the royalties, freehold taxes and related incentives in Alberta, Saskatchewan and British Columbia.

Summary of Provincial Royalties and Freehold Taxes

	Alberta	Saskatchewan	British Columbia
Crown Oil Royalties	- rates vary based on date of discovery, productivity of well, method of recovery and price; - phase-down of marginal rates to: 40% old oil 30% new oil.	- rates vary based on date of discovery, productivity of well, method of recovery and oil quality; - marginal rates: 40% old oil 33% new oil.	- rates vary based on date of discovery, productivity of well and method of recovery; - marginal rates: 40% old oil 30% new oil.
Crown Gas Royalties	- rates vary with date of discovery, productivity of well, method of recovery and price; - phase-down of marginal rates to: 40% old gas 30% new gas.	- for new gas, rates vary with date of discovery, productivity of well and method of recovery; - maximum marginal rate for new gas is 35%; - royalty for old and special old gas = $\$6.57/10^3m^3$.	- rates vary based on five factors: age, location, depth and productivity of well; and price of gas.
Freehold Taxes	- Freehold Mineral Rights Tax based on production and price.	- Freehold Oil Production Tax based on same factors as Crown oil royalty.	- Mineral Land Tax.

	Alberta	Saskatchewan	British Columbia
Oil And Gas Royalty/Tax Reductions And Exemptions	- incremental oil from approved EOR schemes treated as new; - further reductions for extra costs of tertiary projects; - oil sands mining and oil well operations treated differently; - 5% gross royalty for experimental projects; - gas royalty reduced in respect of processing fees; - exploration-related oil and gas royalty reduction; - ownership-related oil and gas tax reduction; - oil and gas well drilling holidays.	- incremental oil from approved EOR schemes treated as new; - 5% gross royalty or tax exemption for post 1980 tertiary projects; - new gas royalty reduced in respect of processing fees; - oil and gas well drilling holidays.	- incremental oil from approved EOR schemes treated as new; - royalty exemption for tertiary pilot projects, approved waterfloods and oil from new pools; - royalty for other tertiary projects equals one-half of new rate during pre-payout period; - gas royalty reduced in respect of processing fees; - oil well drilling holidays.

In addition to the main features listed above, many provinces offer other incentives based on various criteria. These are discussed for each province in the following chapters.

CHAPTER IV
ALBERTA FISCAL REGIME

A. OIL

Conventional oil from Crown lands in Alberta is subject to a price and productivity sensitive royalty regime. In addition, oil from certain sources, such as enhanced oil recovery projects, oil sands projects and experimental projects, is subject to special regimes.

1. Old and New Conventional Oil

a) Definition

There are currently two classes of conventional oil production, from Crown lands in Alberta, subject to royalty. Old oil is from pools discovered prior to April 1, 1974. New oil is from pools discovered after March 31, 1974. New oil also includes the incremental production from enhanced oil recovery schemes as discussed in section 2, below. (See Petroleum Royalty Regulation 93/74, as amended.)

b) Policy Intent

The policy of the Government of Alberta, applicable to a 'reference' well (see below), is to collect 21 2/3 percent of the first $40.90 per cubic metre of oil (the base or select price), plus a marginal rate on that portion of a provincially established "par price" in excess of $40.90 per cubic metre. Both the par and select prices are invariant for different qualities of oil.

On June 24, 1985, the Government of Alberta announced a phased reduction in the marginal royalty rates on old and new oil over a two-year period commencing August 1, 1985. The marginal rates in effect over the period will be as follows:

	Marginal Royalty Rates (%)	
	Old Oil	New Oil
August 1, 1985 to July 31, 1986	43.5	33.5
August 1, 1986 to July 31, 1987	42	32
August 1, 1987+	40	30

The royalty formula delivers the desired royalty on a reference well which was, historically, the average productivity well. While this reference well was once subject to periodic adjustments, it has been, in practice, fixed at 572.1 cubic metres of oil per month since 1978. This fixing of the reference level has a significant impact on average royalty rates. Over time, the actual average productivity has fallen and is expected to fall further below the reference level. As a result, the average royalty rate for a well of average productivity is less than the rate applicable to a well at the reference productivity level. Moreover, the average royalty rate for any given well productivity will be lower than would otherwise be the case if the policy intent was realized at the actual average well output level.

c) Old and New Oil Royalty Formulae

All oil is subject to a basic royalty, S, calculated in cubic metres:

$S\ (m^3) = Q^2/1271.28$, if monthly production, Q, is less than or equal to 190.7 m^3; and

$S\ (m^3) = 28.6 + .25\ (Q - 190.7)$, if monthly production, Q, is greater than 190.7 m^3.

This basic royalty then enters into the appropriate royalty formula to determine the royalty payable in cubic metres, R, on old and new oil. The royalty formula is:

$$R\ (m^3) = S\ (1 + K(A-B)/A)$$

where: A is the par price for the month (equal to $\$120.00/m^3$ for both categories of oil for April 1986);
B is the select price for the month (currently $\$40.90/m^3$ for both categories of oil); and
K is the royalty factor for the month which is set to make the royalty formula equal to the intent formula on the reference well (currently 1.007692 for old oil and 0.546154 for new oil).

(See Crude Oil Par Price and Royalty Factor Regulation (No. 4) 270/85 and The Crude Oil Par Price, Select Price and Royalty Factor Regulation 267/79, as amended.)

The royalty factor for each category of Crown oil production is determined by dividing the intent formula by the par price in order to determine the average royalty rate on the reference well. This rate is multiplied by the reference well volume and equated with the royalty formula, and the resulting equation is then solved for the royalty factor, K. The K factor is independent of oil prices. Moreover, because reference well production has been set at 572.1 cubic metres per month, the royalty factor should remain constant unless the intended marginal royalty rates are changed.

This is easily demonstrable:

Set the intent formula equal to the royalty formula at the reference well in terms of dollars per cubic metre:

$$B\ (S/Q) + M\ (A-B) = A\ (S/Q)\ (1 + K(A-B)/A)$$

where: M is the marginal royalty rate;
Q is the reference well production.

Solving for K, and substituting for S and Q yields:

$$K = (572.1/123.95)\ M - 1$$

Therefore, the royalty factors for the marginal royalty rate, phase-down period should be:

	K (royalty factor)	
	Old Oil	New Oil
August 1, 1985 to July 31, 1986	1.007773	0.546216
August 1, 1986 to July 31, 1987	0.938540	0.476983
August 1, 1987+	0.846228	0.384671

d) Crown Oil Royalty Rates

The tables below present the average and marginal royalty rates as of March 1, 1986, for both old and new oil, for each of a low productivity case, an approximate average productivity case, the reference well case and a high productivity case.

OLD OIL

(Par Price = $120.00/$m^3$)

Monthly Output (cubic metres)	Average Royalty (%)	Marginal Royalty w.r.t. Price (%)
100	13.09	15.79
290(1)	30.66	36.98
572.1(2)	36.06	43.50
1000	38.43	46.36

NEW OIL

(Par Price = $120.00/$m^3$)

Monthly Output (cubic metres)	Average Royalty (%)	Marginal Royalty w.r.t. Price (%)
100	10.70	12.16
310(1)	25.63	29.14
572.1(2)	29.47	33.50
1000	31.41	35.71

Notes: 1. The approximate average productivity: 290 m^3/month for old oil; and 310 m^3/month for new oil.

2. The reference well at which the intended marginal capture, with respect to price changes, is attained: 43.5% for old oil; and 33.5% for new oil.

Figures 4.A.1 and 4.A.2 show the average old and new oil royalty rate for a well of average productivity, at various world oil price levels during the phase-down period. For this purpose, the theoretically correct K factor values, listed on page 38, are used. It is also assumed that the selling price of oil equals the par price. Average oil royalty rates and marginal oil royalty rates with respect to production are presented in Figures 4.B.1 and 4.B.2 for various old and new oil well productivities. In these latter figures, the par price is fixed at its April 1986 level, and the K factor values used are the actual provincial values established on August 1, 1985, and currently in effect.

2. Enhanced Oil Recovery

Incremental production from an approved enhanced recovery scheme is subject to the new oil royalty rate regardless of the original discovery date of the pool. It is possible that a single well could be producing both old and new oil depending on whether an enhanced oil recovery scheme is employed. Thus, 'co-existence factors' are assigned to allocate total production between the two classes, for each project. Enhanced oil recovery schemes include both secondary and tertiary recovery schemes.

In addition to the lower royalty rates which could prevail because of the reclassification of incremental oil obtained by use of an enhanced recovery mechanism, the Alberta Petroleum Royalty Regulations allow for two additional reductions with respect to oil recovered using a tertiary recovery scheme.

First, Section 4 of the Alberta Petroleum Royalty Regulations allows a rebate of royalties payable in respect of natural gas liquids (NGLs) injected into a well. This reduction will equal the lesser of the value of the NGLs injected and 5 percent of the royalty payable on the incremental production. As is the case with a deduction under section 4.2 below, a reduction under Section 4 is subject to approval by the Minister.

Second, Section 4.2 allows a discretionary reduction in royalties payable in consideration of operating and capital costs

Figure 4.A.1
ALBERTA AVERAGE OLD OIL ROYALTY RATES
FOR A 60 BPD WELL

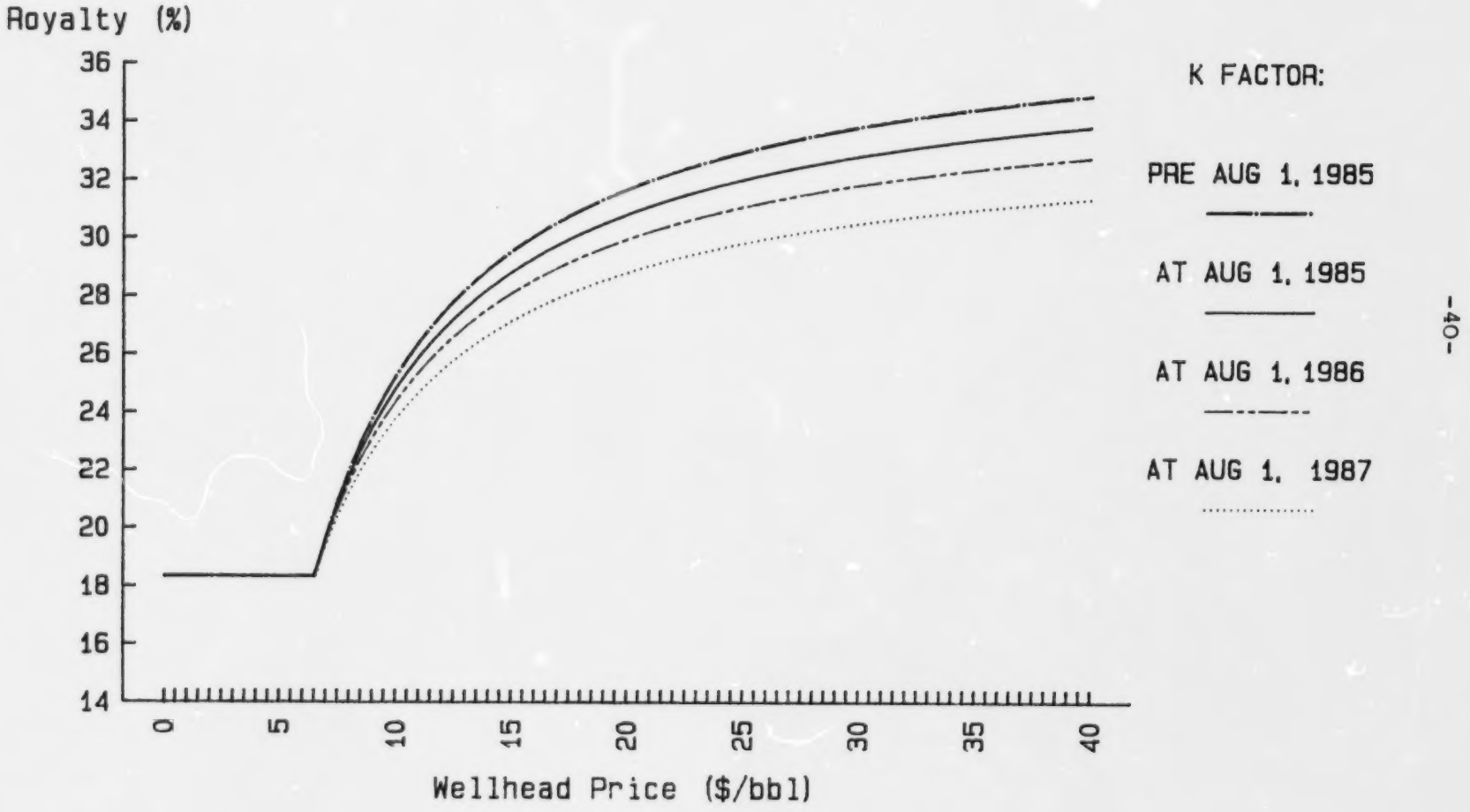


Figure 4.A.2
ALBERTA AVERAGE NEW OIL ROYALTY RATES
FOR A 60 BPD WELL

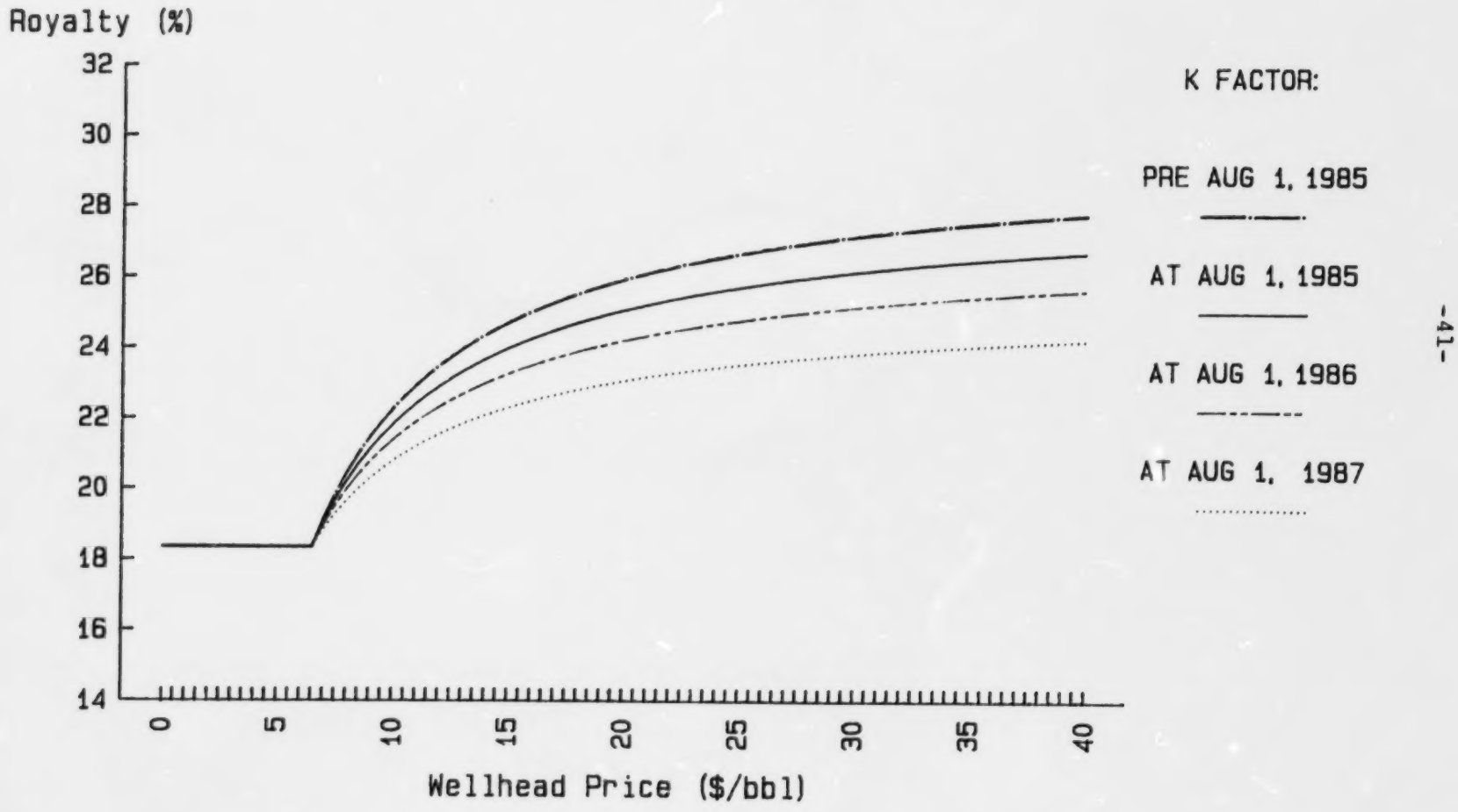


Figure 4.B.1
ALBERTA AVERAGE OIL ROYALTY RATES
FOR A $120 PER CUBIC METRE PAR PRICE

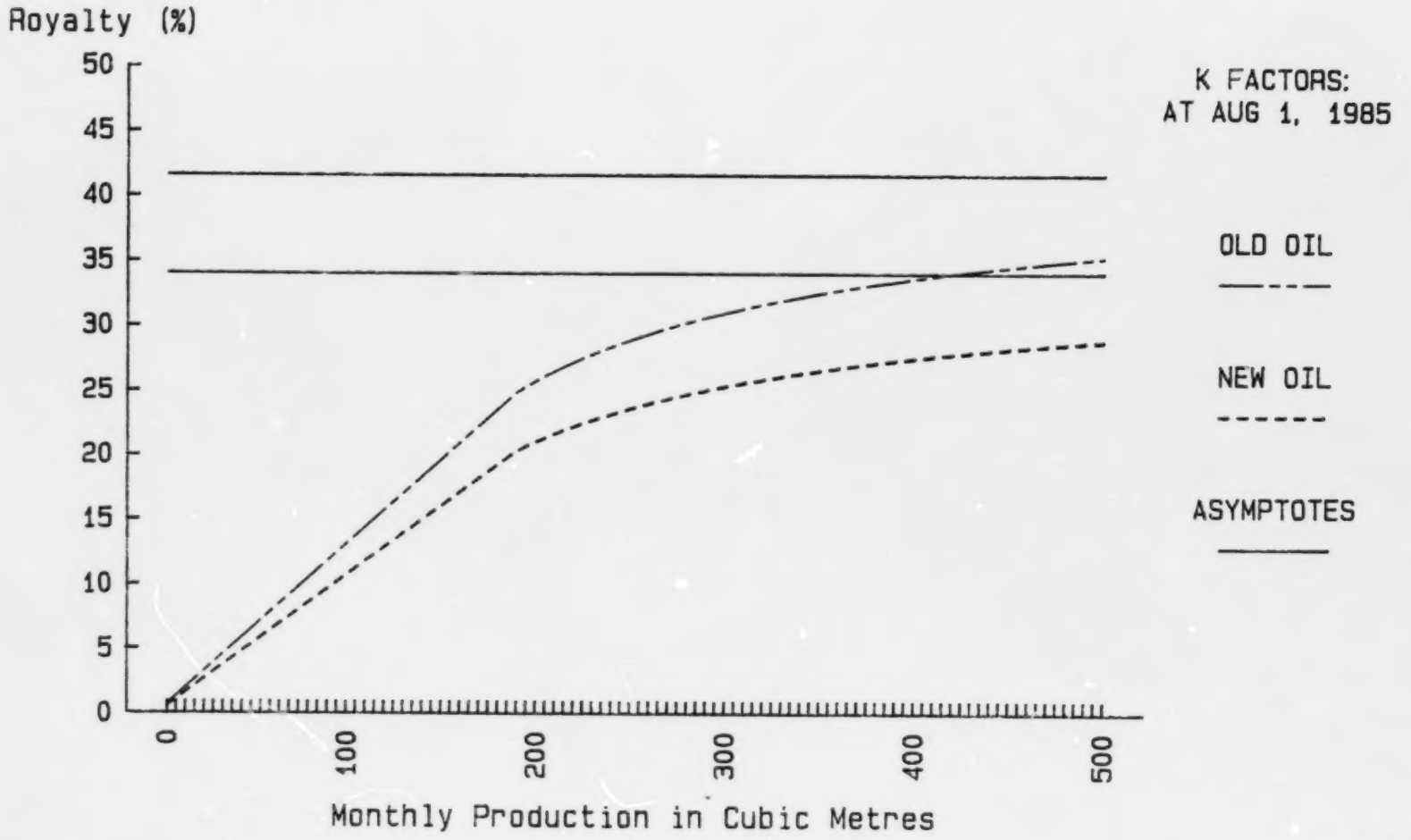
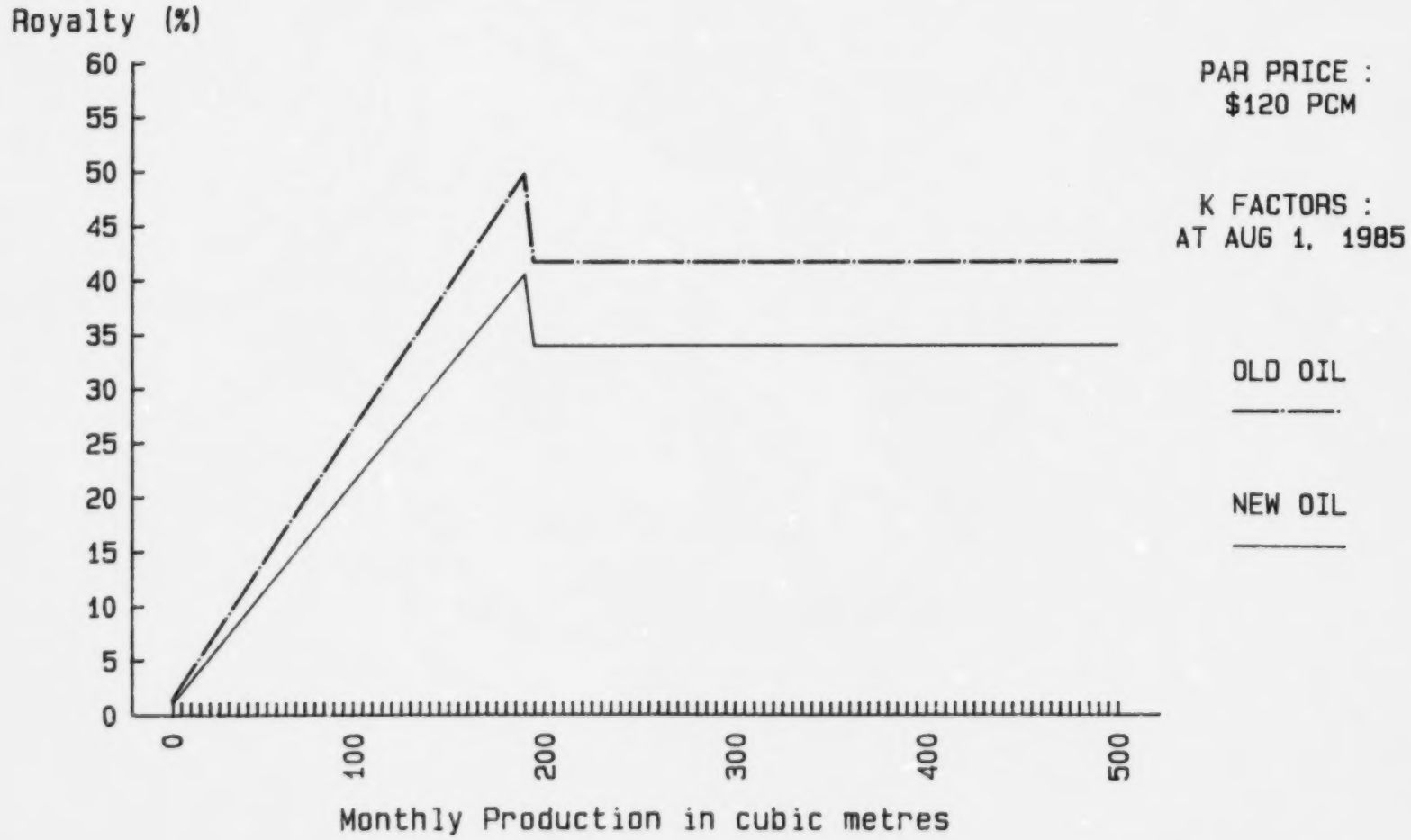


Figure 4.B.2
ALBERTA MARGINAL OIL ROYALTY RATES
WITH RESPECT TO PRODUCTION



incurred in a tertiary recovery project in excess of those that would have been attributable to a suitable waterflood scheme. The excess cost component may be deducted from revenue for a given month prior to calculating the royalty for the month provided "the Minister is satisfied that the total royalty payable to the Crown (the present value over the life of the project) will not be less than if the scheme were not to proceed". The estimates of future royalty receipts are discounted to present value at 10 percent per annum.

The following example illustrates the impact of the royalty reductions provided for in sections 4 and 4.2 of the Alberta Regulations, on the new oil royalty rate. An old field producing 572.1 cubic metres per month and receiving a price of $120.00 per cubic metre, would be subject to an average royalty rate of 36.06 percent. If the field is approved for tertiary recovery, the incremental oil extracted using the approved method will be considered as new oil, receiving the same price of $120.00 per cubic metre, but subject to an average royalty rate, before any royalty reductions, of 29.47 percent.

Assuming the incremental operating costs are $10 for NGLs injected, $25 for other operating costs (e.g., push gases injected) and $22 for incremental capital, a new royalty would be derived as follows for the first year:

i) Royalty = 0.2947 ($120.00) = $35.36
ii) NGL rebate[1] = 0.05 ($35.36) = $1.77
iii) EOR operating costs[2] = 1.25 (0.9($10-$1.77+0.8($25)))
= $31.76
iv) amortized incremental capital cost[3] = 1.25 (0.3($22))
= $8.25
v) cost deduction = items iii) plus iv)
= $31.76 + $8.25 = $40.01
vi) adjusted royalty payable = ($120.00 - $40.01) 0.2947
= $23.57
vii) effective royalty rate = (vi - ii)/price
= (($23.57-$1.77)/$120.00) 100 = 18.17%

Notes: 1. In this example, 5 percent of the royalty payable on the incremental production is less than the value of the NGLs injected and will, therefore, be deducted. In general,

companies do not use the NGL rebate since to do so would require that they pay royalty on the NGLs reproduced.
2. In calculating EOR operating costs, 80 percent of other operating costs are included. Further, 90 percent of EOR operating costs, grossed up by 25 percent to allow for undefined costs and overhead related to the incremental costs incurred, are allowed to be deducted.
3. Incremental capital is subject to a capital allowance of 30 percent on a declining balance basis. The amortized incremental capital cost is grossed by 25 percent to allow for inflation and excluded overhead costs.

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3. Oil Sands

a) Mining Operations

Oil sands mining operations are treated on a case-by-case basis. Synthetic crude oil produced by Suncor Inc. (formerly Great Canadian Oil Sands Limited) is subject to a Crown royalty based on monthly production. For the period April 1, 1986, to December 31, 1986, the royalty rate equals 1 percent. (See Government of Alberta, News Release, April 28, 1986.) In general, however, the rate is 8 percent on the first 143,019 cubic metres of production; 20 percent on the next 74,370 cubic metres; 8 percent on the next 41,316 cubic metres; and 20 percent on any additional production. A royalty reduction is also allowed equal to 3 percent of the production attributable to Suncor's "large pit addition". For products other than synthetic crude oil, the royalty is 16 2/3 percent of such production. (See Suncor Oil Sands Royalty Regulation 318/78, as amended.)

While Syncrude is basically exempt from royalties per se, the Alberta government collects a joint venture payment in lieu of a royalty. This payment is calculated as 50 percent of "profits". As defined by agreement, "profits" are equal to gross revenues less operating costs, deemed interest payments, capital depreciation and any prior losses. (See Alberta Crown Agreement, February 4, 1975.) Note that this quasi-royalty (joint venture payment) paid to Alberta is deductible for federal income tax purposes, by means of the Syncrude Remission Order. Syncrude also receives the resource allowance after the quasi-royalty has been deducted. (See Order in Council P.C. 1976-1026.)

b) Oil Wells

Crude oil may also be recovered from oil sands deposits by means of oil wells. These projects are treated on a case-by-case basis for royalty purposes. In general, however, a 1/5/30 percent royalty is applicable. Prior to project "payout", the royalty initially equals 1 percent of gross revenue and rises every eighteen months in increments of 1 percent, to a maximum of 5 percent of gross revenues. After payout, the royalty equals the greater of 5 percent of gross revenues and 30 percent of net revenues. Net revenues are generally defined as gross revenue from the project minus 110 percent of both operating and allowed capital costs. Project payout occurs when cumulative project revenues equal cumulative allowable operating costs, capital costs and royalties, including a 10 percent return allowance on those expenditures. (See Alberta Order in Council 427/84 (Cold Lake), 870/84 (Peace River) and 966/84 (Wolf Lake).)

4. Experimental Projects

Where an enhanced recovery project or an oil sands project is approved by the Energy Resources Conservation Board as an experimental project, the incremental oil production is not subject to the ordinary Crown royalty, but rather to a flat rate 5 percent royalty. (See Experimental Oil Sands Royalty Regulation 287/77.)

B. NATURAL GAS

1. Old and New Gas

a) Definition

Natural gas in Alberta is divided into two classes. Old gas is from pools discovered prior to January 1, 1974, where some portion of the gas was either consumed or sold prior to that date. New gas is from pools discovered after December 31, 1973, or from pools discovered prior to 1974 provided that none of the gas was either consumed or sold before 1974. (See Natural Gas Royalty Regulation 16/74, as amended.)

b) Policy Intent

The gas royalty is dependent on price and, in most cases, not on quantity. The intent is to capture 22 percent of the first $17.75 per thousand cubic metres plus a marginal rate for price in excess of that base amount.

As is the case for oil, Alberta announced, on June 24, 1985, a phased reduction of marginal royalty rates for both old and new natural gas over a two-year period commencing August 1, 1985. The marginal rates, on price in excess of $17.75 per thousand cubic metres, will be as follows:

	Marginal Royalty Rates (%)	
	Old Gas	New Gas
August 1, 1985 to July 31, 1986	43.5	33.5
August 1, 1986 to July 31, 1987	42	32
August 1, 1987+	40	30

Unlike oil, the gas royalty formula does not incorporate the concept of a reference well. Hence, the formula captures the intended royalty. The exception to this rule is for low productivity wells (i.e., wells producing less than 16,900 cubic metres per day) for which a lower royalty, dependent on both price and quantity produced, is levied.

c) Old and New Gas Royalty Formulae

Old and new gas royalty rates are quoted as a percentage of the average field price per month, F. The low price ($1775¢/10^3m^3$) in the royalty formula is due to the existence of fixed price contracts within the province. For wells producing 16,900 cubic metres per day and over, royalty rates are calculated as follows:

F ($¢/10^3m^3$)	Old and New Gas (%)
less than 1775	22
over 1775	$\frac{39050 + M\ (F-1775)}{F}$

where: M is the relevant marginal royalty rate for the period (see above).

For prices greater than 1,775 cents per thousand cubic metres, the formulae can be simplified and expressed in terms of cents per thousand cubic metres:

Old and New Gas Royalties ($¢/10^3m^3$)	Old Gas	New Gas
August 1, 1985 to July 31, 1986	.435F-381.63¢	.335F-204.13¢
August 1, 1986 to July 31, 1987	.42F -355.00¢	.32F -177.50¢
August 1, 1987+	.40F -319.50¢	.30F -142.00¢

Where the average daily production of natural gas from a gas well is less than 16,900 cubic metres per day, the royalty rates are calculated in an identical manner for both old and new gas according to the equation:

$$R\% = R_C - \frac{(Rc - 5)\ (16.9 - ADP)^2}{(16.9)^2}$$

where: R_C is the royalty rate (old or new as applicable) determined from the above formulae for daily production in excess of 16,900 cubic metres; and
ADP is the average daily production of gas.

This formula results in a minimum royalty rate of 5 percent.

d) Crown Gas Royalty Rates

The following table presents the average gas royalty rates for low and high productivity wells for both old and new gas, assuming a field price of $90.00 per thousand cubic metres. The marginal royalty rates used are 43.5 percent for old gas and 33.5 percent for new gas.

	Old Gas (pre-1974)	New Gas (post 1973)
Low Productivity[1] ($11,500\ m^3$/day)	35.76%	28.55%
High Productivity (over $16,900\ m^3$/day)	39.26%	31.23%

Note: 1. The actual average productivity for natural gas.

Notice that as the field price of natural gas increases, the average royalty rate approaches the marginal rate (currently 43.5 percent and 33.5 percent for old and new gas, respectively). For example, at a field price of $140.00 per thousand cubic metres, the average royalty rates for old and new gas increase to 40.77 percent and 32.04 percent, respectively, on high productivity wells. Price increases also raise the average royalty rates on low productivity wells because price enters these royalty formulae through the base royalty rate term, R_c.

2. Gas Cost Allowance

The total natural gas royalty payable is based on gross revenue. However, a deduction is allowed for processing fees where

the gas is custom processed by a third party. In situations in which the producer gathers, compresses and processes the natural gas and associated by-products himself, the gas cost allowance (GCA) provides a deduction in respect of notional processing fees. The allowance is based on direct operating costs attributable to the gathering, compressing and processing facilities, depreciation and a return on capital. The GCA is determined by the following formula:

GCA = 110% of direct operating costs
+ depreciation
+ 15% of the capital base

where: depreciation is over the remaining useful life of the facility, i.e., the economic life of the remaining gas reserves of the field(s) supplying the facility; and

the capital base = total capital at the beginning of the year
+ (addition of new capital for the current year minus depreciation of all assets)/2
+ 1/6 (110% of direct operating costs)
+ average spare parts inventory
+ land capital

The first two items in the capital base represent the average undepreciated cost of capital in the year. The third item and the average spare parts inventory, which is the sum of the spare parts inventory at the beginning of the period and the spare parts inventory at the end of the period, divided by two, represent the working capital allowance. The last factor is the capital cost of the site on which the facility is located.

The net royalty is computed by, first, computing the gross royalty for all products without regard for the GCA. The gross royalty is divided by gross receipts to derive an equivalent royalty rate. The equivalent royalty rate is then applied to the GCA to determine the royalty deduction or credit. The net royalty payable is the gross royalty less the royalty deduction or credit.

C. PRODUCTS FROM OIL AND NATURAL GAS PRODUCTION

1. Pentanes

Pentanes plus are a mixture comprised mainly of pentanes and heavier hydrocarbons which may contain some butanes and propanes, and which are obtained from the processing of natural gas, condensate or crude oil.

The royalty rates in each month on pentanes plus and new pentanes plus, recovered from natural gas, are calculated in a manner similar to those applicable to natural gas. A base royalty rate of 22 percent on the select price of a cubic metre is supplemented by a marginal charge on that part of the average monthly selling price in excess of the select price. Thus, the royalty is dependent only on price; not on quantity. (See Schedule 2 of Natural Gas Royalty Regulation 16/74, as amended.)

This can be represented algebraically by the formula:

$$R\% = \frac{22(B) + M\ (F-B)}{F}$$

where: F is the average monthly selling price;
B is the select price (currently \$40.90/m^3); and
M is the appropriate marginal rate (currently 50% for pentanes plus and 35% for new pentanes plus).

(See Pentanes Plus Royalty Factor Regulation (No. 3) 265/85.)

As is the case with oil, a coexistence factor may be assigned where the pentanes plus is incremental new pentanes plus recovered as a result of a gas cycling scheme. Thus, pentanes plus from a gas discovery before 1974 can qualify as new pentanes plus if the incremental production results from the use of a gas cycling scheme commenced after 1974.

The above royalty formula also applies to pentanes plus that are condensates at an oil well that are commingled with solution gas or condensates at a gas well that remain in the gas stream, and that are subsequently recovered at a natural gas processing plant. In all other situations, such as condensates at an oil or gas well that are sold as a separate product or that are commingled with crude oil and sold, and where pentanes plus are obtained from crude oil, the oil royalty formulae described in section A, above, apply.

2. Propane, Butane and Mixed Liquified Petroleum Gases

These products, obtained by processing natural gas, are charged a flat rate royalty of 30 percent. (See Schedule 4 of Natural Gas Royalty Regulations.)

3. Sulphur

Sulphur obtained by processing natural gas is charged a flat rate royalty of 16 2/3 percent of production. (See Schedule 3 of Natural Gas Royalty Regulations.) The same royalty rate applies to sulphur obtained from the Suncor oil sands project (see Suncor Oil Sands Royalty Regulation 318/78, as amended).

4. Straddle Plant Natural Gas Liquids

Natural gas liquids (i.e., butane, propane and ethane) derived from natural gas at a straddle plant (i.e., a gas reprocessing plant) are not subject to a direct royalty as they have already been subject to natural gas royalties, which may be lower or higher than the flat rate 30 percent royalty on products obtained from natural gas processing.

D. FREEHOLD MINERAL RIGHTS TAX

The Freehold Mineral Rights Tax is levied on crude oil, solution gas, natural gas and gas well condensate produced from non-Crown owned lands in Alberta. The tax is dependent on both price and well productivity. The rate of tax is substantially below the royalty charged on production from Crown lands. Tax reductions are provided to owners of petroleum and natural gas rights. (See Freehold Mineral Rights Tax Act, S.A. 1983, c. F-19.1, and Freehold Mineral Rights Tax Regulation 12/84.)

1. Crude Oil, Solution Gas and Gas Well Condensate

The tax payable on the production of crude oil, solution gas and gas well condensate from a well is calculated using the following formula:

$$\text{Tax Payable} = R \times V \times M$$

where: R is the prescribed rate of tax (currently 0.269 for crude oil and gas well condensate, and 0.069 for solution gas);

V is the price per cubic metre of crude oil and gas well condensate, and the price per thousand cubic metres of solution gas; and

M is the annual production of solution gas in thousand cubic metres and, for crude oil and gas well condensate, is the amount in cubic metres determined by the following formulae:

$M = \frac{(0.0833\ Q)^2}{105.94}$, if annual production, Q, from the well is less than 2,288.4 m^3; and

$M = \frac{Q}{4} - 228.84$, if annual production, Q, from the well is greater than or equal to 2,288.4 m^3.

2. Natural Gas

Where average daily production of natural gas for a taxation year is less than 16.9 thousand cubic metres, the tax payable is calculated using the following formula:

Tax Payable = A x V x M

where: $A = R - \frac{(R - 0.01)(16.9 - ADP)^2}{(16.9)^2}$

R is the prescribed rate of tax (currently 0.069);
ADP is the average daily production from the well;
V is the price per thousand cubic metres; and
M is the annual production in thousand cubic metres from the well.

Where the average daily production of natural gas for a taxation year is greater than or equal to 16.9 thousand cubic metres, the tax payable is calculated using the formula:

Tax Payable = R x V x M

where: R is the prescribed rate of tax (currently 0.069);
V is the price per thousand cubic metres; and
M is the annual production in thousand cubic metres from the well.

3. Reductions in Tax

The Freehold Mineral Rights Tax may be reduced in certain circumstances depending on the ownership of petroleum and natural gas rights. Where a taxpayer only owns a petroleum right, the tax payable on crude oil and on solution gas may each be reduced by a maximum of $1,600. The total taxes payable on natural gas and gas well condensate may be reduced by up to $1,600 where a taxpayer only owns a natural gas right. Where a taxpayer owns both the petroleum and natural gas rights, the tax payable on crude oil may be reduced by a maximum of $1,600, and the total taxes payable on solution gas, natural gas and gas well condensate may be reduced by up to $1,600.

E. INCENTIVE PROGRAMS

1. Alberta Petroleum Incentives Program

The Alberta Petroleum Incentives Program (APIP) is administered and funded by the Alberta government. It is modelled after the federal Petroleum Incentives Program. As is the case with PIP, APIP was terminated on March 31, 1986. Certain activities are also grandfathered, but only until December 31, 1986. (See APIP Act, S.A. 1981, C. P-4.1, as amended, and Regulation 220/82, as amended.)

2. Crude Oil Royalty Holiday Program

Under the Crude Oil Royalty Holiday Program, a royalty exemption is provided to crude oil production from eligible wells in Alberta. In order to qualify, the drilling or deepening of a well must commence between June 1, 1985, and May 31, 1988.

The Crude Oil Royalty Holiday Program is designed to promote exploration for conventional oil in Alberta. Consequently, wells drilled into oil sands deposits are not eligible wells. Neither are experimental nor off-target wells. Wells that are part of a tertiary oil recovery project may qualify for either 4.2 relief (see subsection A.2, above) or a royalty holiday under this program, but not both. Further, wells drilled on freehold lands in the province are not eligible wells. (See Petroleum Royalty Regulation 93/74, as amended, and Alberta Energy and Natural Resources Technical Report Number T/94.)

The royalty holiday for each eligible exploratory oil well consists of the greater of:

i) a one-year royalty-free period; or
ii) a royalty exemption defined as a volume of crude oil, in cubic metres, based on the depth and on the location of the eligible well within the province.

In both cases, the maximum value of the royalty holiday is $1 million. The depth and location related royalty exemption is designed to allow low productivity wells to continue to produce royalty-free oil beyond the one-year period, but before the $1 million limit is reached. The royalty holiday may be used to reduce Crown royalties otherwise payable until June 1, 1993. At the discretion of the Minister, the royalty holiday may be transferred from an eligible well that is determined to be damaged to its twin well.

The Crude Oil Royalty Holiday Program replaced the royalty holidays for exploratory oil wells that had previously been provided under the Exploratory Drilling Incentive System (EDIS) and the Oil Royalty Exemption System (ORES). During the two-month period June 1, 1985, to July 31, 1985, when the EDIS and ORES were still in effect, a producer could elect to apply for royalty exemption under either the Crude Oil Royalty Holiday Program, or the EDIS or ORES. (See Appendix I, section B for a discussion of the EDIS and ORES).

3. Exploratory Gas Well Incentive Program

The Exploratory Gas Well Incentive Program provides royalty holidays to production from exploratory gas wells in Alberta. Eligible wells are those, the drilling or deepening of which commenced between August 1, 1985, and May 31, 1988. Also eligible are gas wells drilled between June 1, 1985, and July 31, 1985, and which qualified as incentive exploratory wells under the EDIS, if the producer forgoes all incentives under the EDIS. Exempt natural gas production is that production from a natural gas bearing interval below a depth of 600 metres, and which is obtained from a pool in which there is no other well located within 4.8 kilometres of the exploratory gas well that is exempt from royalty under either the Exploratory Gas Well Incentive Program or the EDIS. (See Natural Gas Royalty Regulation 16/74, as amended, and Alberta Energy and Natural Resources Technical Report Number T/94.)

The royalty holiday for each exploratory gas well consists of the greater of:

i) a one-year royalty-free period; or

ii) a royalty exemption defined as a dollar amount to be applied against royalties payable from the sale of natural gas and products from the well, based on the depth and location of the well within the province.

In both cases, the maximum value of the royalty holiday is $2 million. A royalty holiday may be transferred from an exploratory gas well that is determined to be damaged to its twin well on approval of the Minister. Royalty holidays may be used to offset Crown royalties otherwise payable until June 1, 1988. The Exploratory Gas Well Incentive Program does not apply to wells drilled on freehold lands in Alberta.

4. Deep Gas Royalty Holiday Program

Under the Deep Gas Royalty Holiday Program, royalty holidays are provided to production from eligible deep gas wells. Eligible wells are those, the drilling or deepening of which commenced after May 31, 1985, and which are drilled to a depth of more than 2,500 metres. Exempt natural gas production is that production from a pool lying below 2,500 metres. A well may qualify for either the Exploratory Gas Well Incentive Program or the Deep Gas Royalty Holiday Program, but not both. (See Natural Gas Royalty Regulation 16/74, as amended, and Alberta Energy and Natural Resources Technical Report Number T/94.)

The royalty holiday for eligible deep gas wells is defined in terms of a dollar amount dependent on the depth of the well below 2,500 metres. At the discretion of the Minister, the royalty holiday may be transferred from an eligible well that is determined to be damaged to its twin well. Royalty holidays may be used to offset Crown royalties otherwise payable on production from the eligible well (or its twin) for a period not exceeding ten years after the completion of the drilling or deepening. The Deep Gas Royalty Holiday Program is not applicable to wells drilled on freehold lands in Alberta.

5. Exploratory Drilling Assistance Program

Under the Exploratory Drilling Assistance Program (EDAP), 50 percent of eligible expenditures on approved exploration wells drilled over the period April 1, 1986, to December 31, 1986, will be permitted to reduce Crown royalties otherwise payable after March 31, 1987. Eligible expenditures include well-specific intangible drilling and overhead costs. Total benefits available under the EDAP are limited to $300 million.

Credits earned by one taxpayer under the EDAP may be transferred to other taxpayers. Further, credits received do not reduce the amount of Alberta royalty tax credit (discussed in subsection F.3, below) otherwise available to a taxpayer. Wells on which EDAP credits are earned, however, are not eligible for APIP payments in respect of drilling costs but may be eligible for APIP grants in respect of completion costs. (See Alberta Energy and Natural Resources, Information Letter 86-10, "Exploratory Drilling Assistance Program (EDAP)" and Government of Alberta, News Release, April 1, 1986, "Alberta Government Announces Immediate $400 Million Initiative to Aid Energy Industry".)

F. CORPORATE INCOME TAX

1. Rates of Tax

The provincial income tax rate on corporate income earned in Alberta is 11 percent, with a 6 percent deduction for firms that qualify as small businesses. (See Alberta Corporate Income Tax Act, R.S.A. 1980, c. A-17, as amended.)

For the period April 1, 1985, to March 31, 1990, the rate of provincial tax on income from manufacturing and processing activities that qualify for the small business deduction is reduced from 5 percent to nil. The rate applicable on other manufacturing and processing income is reduced from 11 percent to 5 percent.

2. Royalty Tax Deduction

An area in which the Alberta and federal Acts differ is in respect of Crown royalties. The federal Act does not allow such royalties to be deducted in calculating taxable income. By means of a royalty tax deduction, Alberta allows a deduction equal to the difference between the resource allowance claimed and the disallowed Crown royalty payable. In cases where this deduction is unusable in a taxation year, it is able to be carried forward indefinitely. In cases where the resource allowance exceeds Crown royalties payable, no royalty tax deduction is available, nor is such excess taxed.

3. Royalty Tax Credit

A tax reduction is provided by means of the Alberta royalty tax credit. Effective April 1, 1986, individuals and corporations that pay Alberta Crown royalties are able to claim a tax credit equal to 95 percent of their Alberta royalty payments for the period April 1, 1986, to December 31, 1986, to a maximum of $3 million per year. (See Government of Alberta, News Release, April 1, 1986, "Alberta Government Announces Immediate $400 Million Initiative to Aid Energy Industry".) Effective January 1, 1987, the credit will equal 75 percent of Alberta royalties to a maximum of $3 million per year.

The upper limit serves to direct the major portion of this incentive to individuals and smaller companies. Further, the credit is refundable so that any earned credit in excess of Alberta income tax otherwise payable may be received by the taxpayer in the year in which it is claimed. A firm may also reduce its Alberta income tax installments by its anticipated credit or, for non-taxpaying companies, the credit may be received on a monthly basis.

ADDENDUM TO CHAPTER IV

On June 4, 1986, the Government of Alberta announced three temporary programs designed to provide assistance to the province's petroleum industry. Described below, they are:

i) the Development Drilling Assistance Program;
ii) the Well Servicing Assistance Program; and
iii) the Geophysical Assistance Program.

(See Government of Alberta, News Release, June 4, 1986, "Energy Minister Announces New Assistance Programs for Oil and Gas Industry".)

1. Development Drilling Assistance Program

Under the Development Drilling Assistance Program (DDAP), 40 percent of eligible drilling costs incurred below a depth of 400 metres on development and injection wells which commence drilling on Crown lands during the four-month period, June 4, 1986, to September 30, 1986, will be eligible for either cash grants or transferable credits against royalties otherwise payable, to a maximum of $200,000 per well. Total benefits available under the DDAP are limited to $100 million.

2. Well Servicing Assistance Program

The Well Servicing Assistance Program (WSAP) applies to eligible contract labour costs incurred for the maintenance and service of eligible wells, pipelines and batteries between June 4, 1986, and September 30, 1986. Under the program, 50 percent

.../2

of such costs will be eligible for a cash grant to a maximum of $50,000 per eligible well and for pipelines, and $100,000 for batteries. Total benefits available under the WSAP are limited to $50 million.

3. Geophysical Assistance Program

Under the Geophysical Assistance Program (GAP), 35 percent of field expenses incurred over the period June 4, 1986, to December 31, 1986, on eligible reflection seismic work conducted on Crown lands and lands within 1.7 kilometres of Crown lands will be eligible for either cash grants or transferable credits against royalties otherwise payable. Total benefits available under the GAP are limited to $50 million.

Financial and Market Analysis Branch
Energy, Mines and Resources Canada
June 1986

CHAPTER V
SASKATCHEWAN FISCAL REGIME

A. OIL

1. Old and New Oil

a) Definition

There are currently three classes of Crown oil production in Saskatchewan: old oil, new oil and enhanced oil recovery (EOR) oil. (See Petroleum and Natural Gas Regulation 8/69, as amended.)

Old oil is from wells completed prior to 1974 and new oil is from wells completed after 1973. As is the case in Alberta, the operation of an enhanced recovery scheme can redefine oil for royalty purposes. Thus, incremental production from either a secondary recovery project which commenced operation after 1973 or a tertiary recovery project which commenced operation between 1974 and 1980, is also defined as new oil. EOR oil is the incremental production from a tertiary oil recovery project which commenced operation after 1980. (EOR oil royalties are described in section 2, below.)

The Minister can assign coexistence factors for wells producing more than one type of oil. He may also reclassify oil at his discretion: all old oil from the Lloydminster and Kindersley heavy oil areas, old oil from wells producing less than 10 barrels per day (48 cubic metres per month) that was reclassified in July 1982, oil from wells engaged in an approved expenditure program to improve production (e.g., well workovers), and medium crude oil from the southwest area of the province are deemed to be new oil for royalty/tax purposes.

b) Policy Intent

Saskatchewan signed a Memorandum of Agreement with the federal government on October 26, 1981, and altered its royalty regime such that, on average, 50 percent of any price increase on or after July 1, 1982, (with respect to old or new Crown oil) would be captured. As of July 6, 1982, Saskatchewan stated that it would levy marginal royalty rates of 40 percent on both old and new oil. This was a return to the pre-agreement rate on new oil and a reduction in the old oil royalty rate.

The Amending Agreement of August 1, 1983, did not change the policy intent of the Saskatchewan government with respect to old oil. However, oil previously defined as new oil was reclassified as NORP oil. For NORP oil, the marginal provincial rate was reduced to 33 percent. NORP oil was, in turn, redefined as new oil, effective June 1, 1985.

It has been the intention of the Saskatchewan government that Crown and freehold production would face the same royalty-tax burden. Under the Freehold Oil and Gas Production Tax Act, therefore, Saskatchewan levies a lower tax on freehold production to account for the payment of a royalty to the freehold land owner. Saskatchewan amended its categories of freehold oil, effective June 1, 1985, to make them consistent with the Crown oil definitions outlined above. In order that the Crown and freehold royalty-tax burden be equivalent, Saskatchewan has been forced to retain a pre-August 1, 1983, definition of new oil (discussed in Appendix I, section C) for purposes of the Freehold Oil Production Tax. (See Freehold Oil and Gas Production Tax Regulation 11/83.)

c) Crown Royalty and Freehold Oil Production Tax Formulae

The royalty formulae applicable to production of old and new oil from Crown and freehold lands are identical in form but with different factor values. For low productivity wells (output from 0 to 43 cubic metres per month, inclusive), the formula is:

$$R\% = (AAF)(C)(MOP) - PTF$$

For high productivity wells (output greater than 43 cubic metres per month), the formula is:

$$R\% = (AAF)(K - (X/MOP)) - PTF$$

In both cases: AAF is the Area Adjustment Factor which is used to distinguish between light and heavy crude;
MOP is the Monthly Oil Production in cubic metres;
PTF is the production tax factor, a reduction for freehold and Crown-acquired production; and
C, K and X are constants.

The table below presents the values of these factors as of June 1, 1985.

Oil Royalty Factor Values

	Old Oil	New Oil
C	0.6016	0.4776
K	51.8	41.0
X	1115	880
AAF-light	1	1
-heavy	N/A	0.86
PTF-Crown	0	0
-Crown acquired:	Existing lease rate	Existing lease rate
-freehold[1]	6.9	8.3 or 11.0 (depending on the type of well)

Note: 1. The PTF of 11.0 is applicable to new freehold oil that is oil from wells completed after 1980 or that is designated as new freehold oil by the Minister. The PTF of 8.3 applies to all other categories of new freehold oil.

It should be noted that the oil royalty rates depend on well productivity, but not on price. Thus, as output from a well producing light crude oil on Crown lands increases, the royalty rate will rise from 0 percent (for output 0) and approach the marginal rate, K. Changes in the price of oil, on the other hand, will not directly affect the royalty rate applicable to a given level of well productivity. By adjusting the constants C, K and X, however, Saskatchewan can take into account changes in average well productivity, total provincial output and oil prices to achieve its policy intent.

d) Crown Oil Royalty Rates

The tables below present the average and marginal Crown oil royalty rates as of June 1, 1985, for old and new light oil and new heavy oil for each of a low productivity case, the actual average productivity case, and a high productivity case. No heavy oil is classified as old oil.

OLD LIGHT OIL

Monthly Output (m^3)	Average Royalty (%)	Marginal Royalty w.r.t. Production (%)
30 (1)	18.05	36.10
90 (2)	39.41	51.80
300	48.08	51.80

NEW LIGHT OIL

Monthly Output (m^3)	Average Royalty (%)	Marginal Royalty w.r.t. Production (%)
30 (1)	14.33	28.66
55 (2)	25.00	41.00
300	38.07	41.00

NEW HEAVY OIL

Monthly Output (m^3)	Average Royalty (%)	Marginal Royalty w.r.t. Production (%)
30 (1)	12.32	24.64
75 (2)	25.17	35.26
300	32.74	35.26

Notes: 1. Low productivity is defined to be 43 m^3/month or less for Crown oil and freehold oil.
2. The actual average productivity: 90 m^3/month for old light oil; 55 m^3/month for new light oil; and 75 m^3/month for new heavy oil.

Average oil royalty rates for each of the old and new light, and new heavy oil categories are shown in Figure 5.A.1 for wells of various productivities. Figure 5.A.2 shows marginal oil royalty rates with respect to production for wells of various productivities for each of the oil categories.

2. EOR Oil

As mentioned above, EOR oil is incremental production from a tertiary oil recovery project which commenced operation after 1980. EOR oil produced from Crown lands in Saskatchewan is subject to a reduced royalty equal to 5 percent of gross revenue. The Freehold Oil Production Tax is not applicable to EOR oil produced from freehold lands in the province.

Figure 5.A.1
SASKATCHEWAN AVERAGE OIL ROYALTY RATES

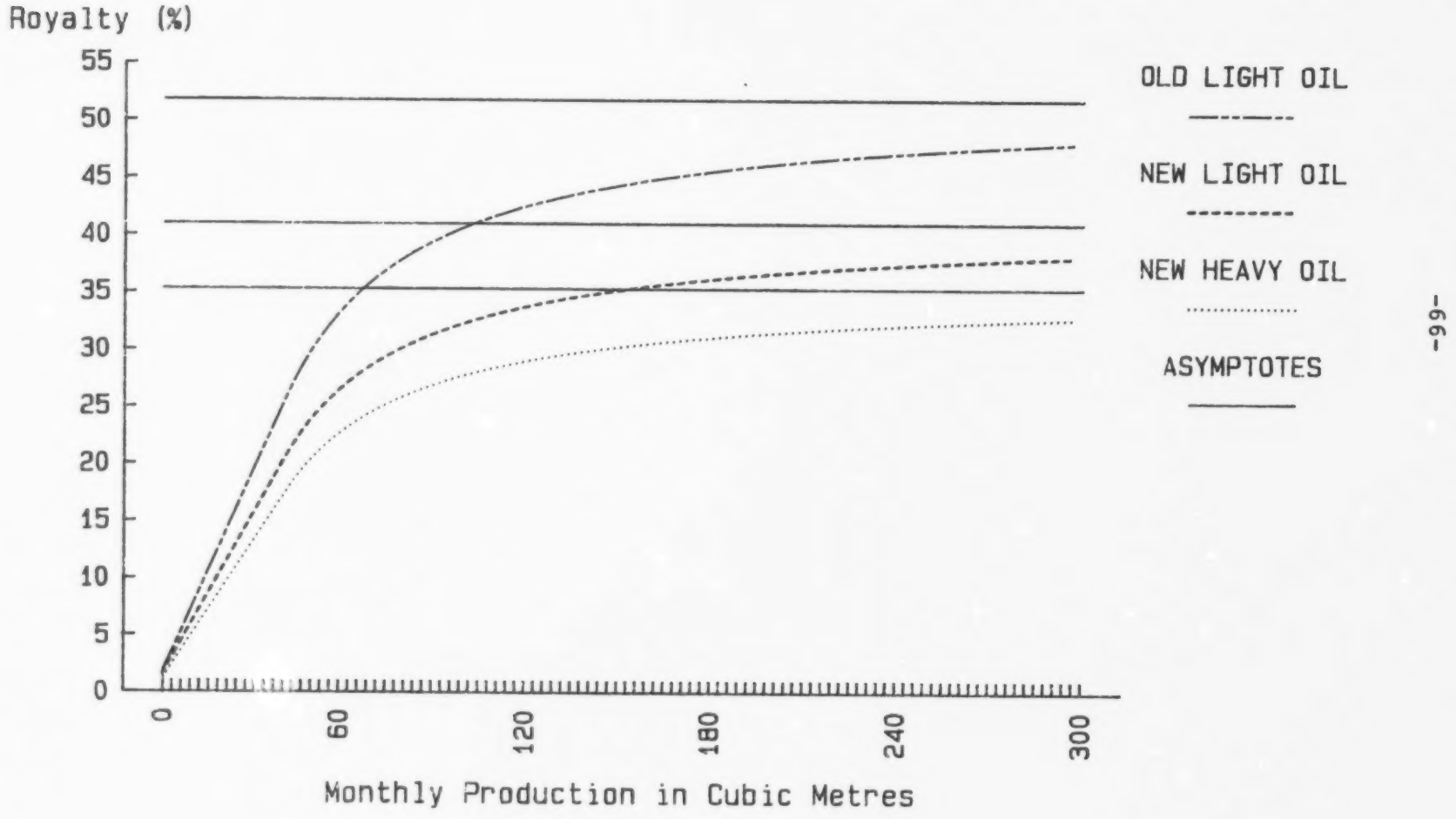
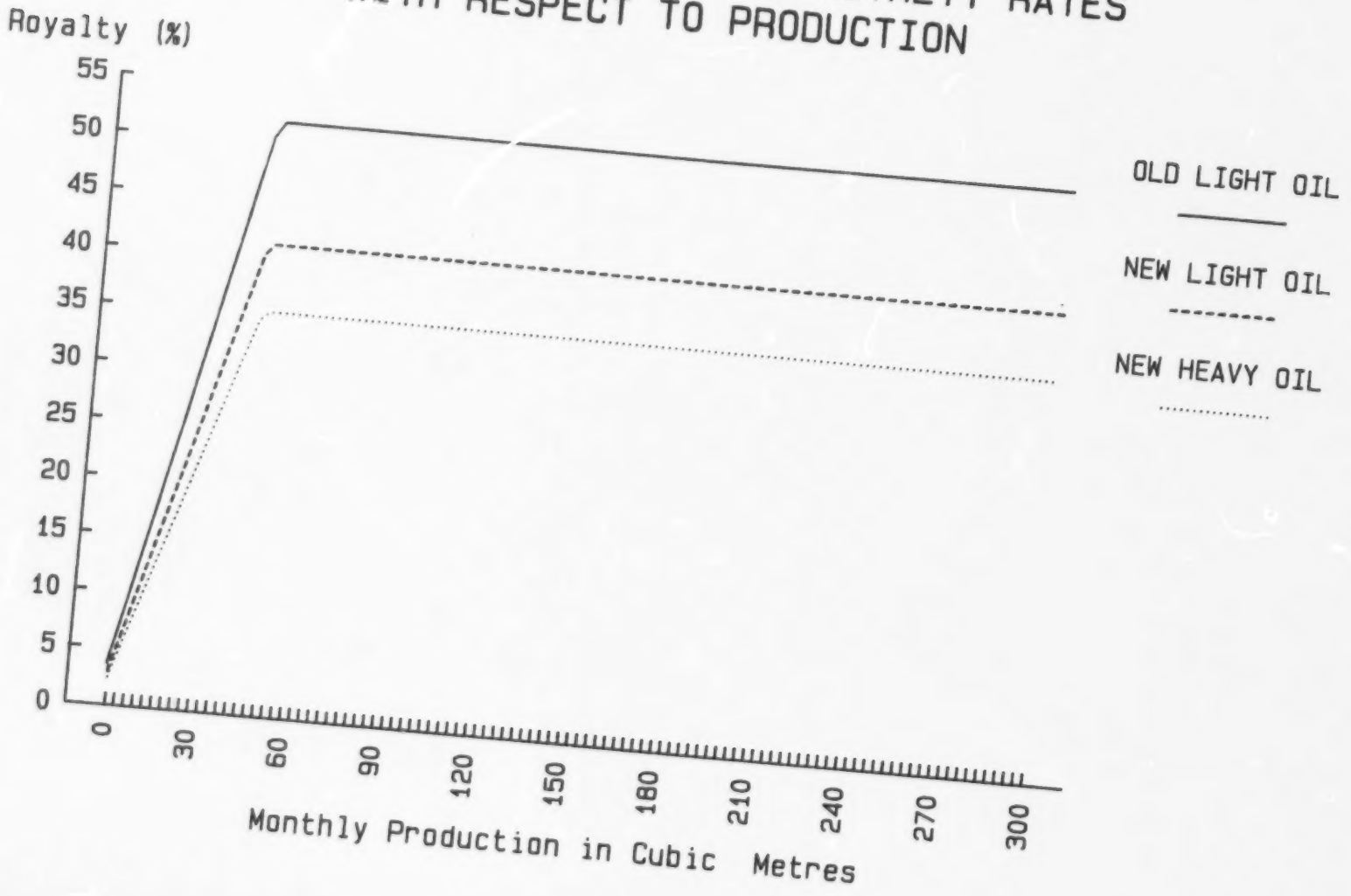


Figure 5.A.2
SASKATCHEWAN MARGINAL OIL ROYALTY RATES
WITH RESPECT TO PRODUCTION



B. NATURAL GAS

There are currently three classes of natural gas production in Saskatchewan, subject to royalty: old gas, special old gas and new gas. Old and special old gas are subject to a flat rate royalty while the royalty applicable to new gas is sensitive to production. The new gas royalty was implemented on July 1, 1985. Prior to this time, a flat rate royalty was levied on all natural gas produced within the province. (See Appendix I, section C for a discussion of the pre-July 1, 1985, royalty regime.)

1. Old and Special Old Gas

a) Definition

Old gas is from wells which commenced operation prior to October 1, 1976. Special old gas is from wells which commenced operation after September 31, 1976, other than those which are part of a gas project which commenced operation after October 31, 1982. Old gas may be reclassified as special old gas if it is from a well which was abandoned and subsequently re-entered, or which was deepened to a new producing zone, after September 31, 1976. The Minister may also designate any natural gas to be special old gas. (See Petroleum and Natural Gas Regulation 8/69, as amended.)

Prior to July 1, 1985, two classes of gas production existed in Saskatchewan, subject to royalty: old gas and new gas. This new gas category has essentially been redefined as special old gas under the post June 30, 1985, regime.

b) Old and Special Old Gas Royalty

Old and special old gas are subject to a flat rate royalty of $6.57 per thousand cubic metres. Where special old gas receives a price in excess of the regulated fieldgate price, however, an additional royalty per thousand cubic metres is imposed equal to 20 percent of the difference. In general, however, the royalty

applicable to old and special old gas is neither price nor productivity sensitive.

Old and special old gas prices, on the other hand, are sensitive to well productivity. Previously, the policy of the Government of Saskatchewan was to increase the flat rate royalty by 20 percent of any increase in the Alberta border price for gas. In light of the recent downward pressure on natural gas prices, however, Saskatchewan is currently re-evaluating the old and special old gas royalty.

2. New Gas

a) Definition

New gas is from wells within gas projects which commenced operation after October 31, 1982. The Minister may also designate any natural gas to be new gas. (See Petroleum and Natural Gas Regulation 8/69, as amended.)

b) New Gas Royalty Formulae

On July 17, 1985, the Government of Saskatchewan announced a new royalty regime for new gas production, effective from July 1, 1985. The new gas royalty is sensitive to well productivity, but not to price, similar to the royalty levied on old and new oil in the province. The royalty formulae for new gas are as follows:

$R\% = Q/6$, if monthly production, Q, is less than or equal to 90 thousand cubic metres; and

$R\% = 35-(2400/(Q+30))$, if monthly production, Q, is greater than 90 thousand cubic metres.

The maximum marginal royalty rate, applicable to high productivity wells, is 35 percent.

c) Crown Gas Royalty Rates

The following table presents average and marginal new gas royalty rates for each of a low productivity case and a high productivity case. Average new gas royalty rates, for various well productivities, are shown in Figure 5.B. Also shown in Figure 5.B are marginal new gas royalty rates with respect to production for wells of various productivities.

	Average Rate (%)	Marginal Rate w.r.t. Production (%)
Low Productivity ($40,000\ M^3$/month)	6.67	13.33
High Productivity ($210,000\ M^3$/month)[1]	25.00	33.75

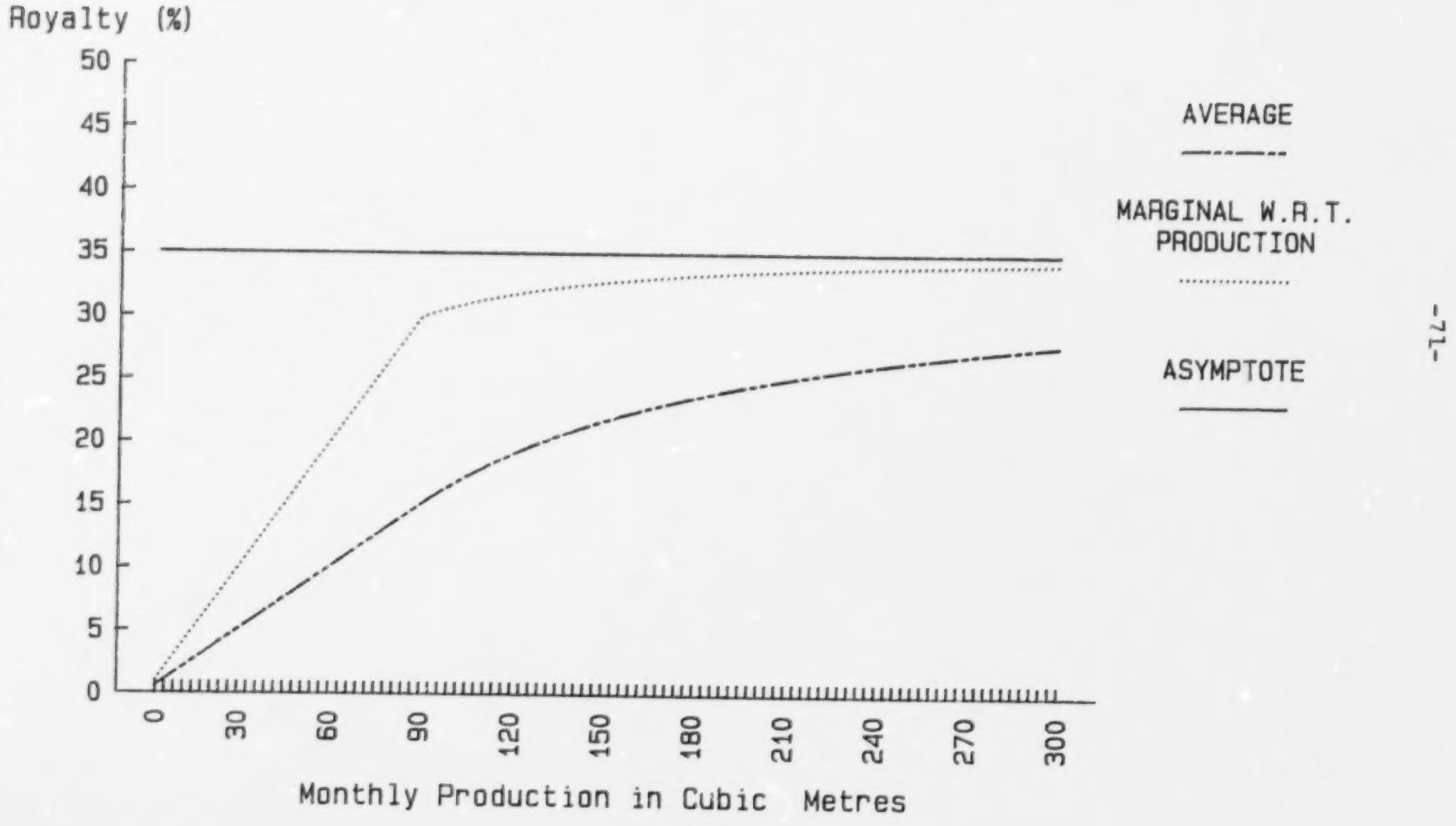
Note: 1. The actual average productivity for new gas.

Notice that as well productivity increases, the average royalty rate approaches the maximum marginal royalty rate. For example, for monthly well production of 500 thousand cubic metres, the average and marginal new gas royalty rates rise to 30.47 percent and 34.74 percent, respectively.

3. Gas Cost Allowance

The gas cost allowance is set at a fixed rate of $10 per thousand cubic metres for all new gas projects. It is deducted from the fieldgate price for gas received by producers. The allowance is designed to compensate the producer for the costs incurred in gathering, processing and compressing gas to pipeline specifications. (See Petroleum and Natural Gas Regulation 8/69, as amended.)

Figure 5.B.
SASKATCHEWAN
AVERAGE AND MARGINAL NEW GAS ROYALTY RATES



C. INCENTIVES

A five-year royalty holiday is available for production from deep exploratory wells completed after May 31, 1982. Production from non-deep exploratory wells that are completed after December 31, 1982, and from deep development wells that are completed after May 31, 1982, is eligible for a three-year royalty holiday. Production from all other wells completed within the province between June 1, 1982, and December 31, 1986, is eligible for a one-year royalty holiday. A one-year royalty holiday is also provided to incremental production from any new or expanded waterflood project approved after December 31, 1982. (See Petroleum and Natural Gas Regulation 8/69, as amended.)

D. CORPORATE INCOME TAX

The provincial corporate income tax rate on income earned in Saskatchewan is 17 percent. It is reduced by 7 percent for firms that qualify as small businesses. Corporate income tax is not payable by small manufacturing and processing corporations in Saskatchewan. Qualifying new small businesses incorporated between March 27, 1986, and March 26, 1988, will be given a two-year tax holiday. There is also a rebate system, similar, in intent, to that which operates in Alberta as a deduction in the calculation of net resource income, by which royalties are made deductible for provincial income tax purposes. (See The Income Tax Act, R.S.S. 1978, c. I-2, as amended.)

A tax of 0.5 of one percent of paid-up capital is levied on corporations in Saskatchewan. (See The Corporation Capital Tax Act, S.S. 1979-80, Chapter C-38.1, as amended.)

ADDENDUM TO CHAPTER V

On May 2, 1986, the Government of Saskatchewan introduced the Oilfield Employment Program. Its components are described below. (See Saskatchewan Energy and Mines, New Release 86-313, "Hepworth Announces Oilfield Employment Program", and Information Circular PNG 86IC01, "Service and Supply Employment Program".)

1. Short-Term Measures

For the three-month period May 1, 1986, to July 31, 1986, the following measures will be implemented:

a) Crown oil royalty and Freehold Oil Production Tax rates will be reduced, subject to a minimum one percent royalty rate, by:

   i) 5 percentage points for new light oil;
   ii) 10 percentage points for old light oil; and
   iii) 15 percentage points for new heavy oil.

b) a Service and Supply Employment Program will be introduced under which 40 percent of approved, eligible contracted service, repair and maintenance costs will be deductible against royalties and freehold taxes otherwise payable. The total benefits available under the program will be limited to $6 million.

It should be noted that these short-term initiatives will be reviewed should oil prices rise prior to August 1, 1986.

2. Long-Term Measures

The royalty/tax structure applicable to enhanced oil recovery (EOR) projects in Saskatchewan will be modified effective May 1, 1986. In contrast to the former 5 percent gross royalty, royalty/tax rates will be dependent on whether or not an EOR project has achieved "payout".

The Crown royalty will equal:

i) prior to project payout and subject to a minimum 1 percent gross royalty, the lesser of 5 percent of gross revenues and 10 percent of net revenues; and

ii) after payout, the greater of 5 percent of gross revenues and 30 percent of net revenues.

Pre-payout production from freehold lands will remain exempt from the Freehold Oil Production Tax. The tax will equal 23 percent of net EOR revenues after payout.

In all cases, net revenues are defined as gross revenues minus operating costs and freehold taxes for the project. Project payout essentially occurs when the present value, at 10 percent per year, of cumulative net revenues minus cumulative project royalty payments equals the value of the initial investment in the project.

It was originally proposed that the EOR royalty/tax regime be modified, in a manner similar to that outlined above, in a July 1982 policy announcement.

Financial and Market Analysis Branch
Energy, Mines and Resources Canada
May 1986

CHAPTER VI
BRITISH COLUMBIA FISCAL REGIME

A. OIL

a) Definition

There are currently two classes of oil production in British Columbia which are subject to royalty: old oil and new oil. Old oil is produced from pools or portions thereof in which there were wells completed prior to November 1, 1975. New oil is produced from pools in which there were no wells completed prior to November 1, 1975.

The new oil definition also includes all incremental oil production recovered from approved new or upgraded waterflood schemes, or tertiary recovery pilot schemes, which commenced operation after October 31, 1975. In addition, oil production from a well in a pool defined prior to November 1, 1975, which has not produced oil for three consecutive years prior to the resumption of production from it after December 31, 1980, and has not been converted to an injection, passive maintenance or observation well is considered as new oil. (See Petroleum and Natural Gas Royalty Regulation 200/85, as amended.)

b) Royalty Formulae

The royalty rate applicable to old oil is determined by the following formulae:

$R(m^3) = Q^2/792$, if monthly production, Q, is less than or equal to 95 cubic metres; and

$R(m^3) = 11.4 + 0.4\ (Q-95)$, if monthly production, Q, is greater than 95 cubic metres.

The royalty formulae for new oil and incremental oil from approved waterflood projects are identical in form but with different factor values:

$R(m^3) = Q^2/1058$, if monthly production, Q, is less than or equal to 159 cubic metres; and

$R(m^3) = 23.9 + 0.3\ (Q-159)$, if monthly production, Q, is greater than 159 cubic metres.

Thus, for successively higher productivity wells, the marginal rates for old and new/incremental waterflood oil approach the maximum marginal rates of 40 percent and 30 percent, respectively. The average rates rise with production from zero to the marginal rates, but are not dependent on the price of oil.

The Mineral Land Tax on freehold production is roughly equivalent to 85 percent of the new oil royalty. (See Mineral Land Tax Act, R.S.B.C. 1979, c. 260, as amended.)

B. NATURAL GAS

Major changes were made to the natural gas pricing and royalty regime in British Columbia, effective July 1, 1985. The restructuring was undertaken in order to stimulate exploration, development and marketing of natural gas in the province. More specifically, the main objectives stated in "The Natural Gas Price Act: A Background Paper", July 1985, were:

- to reduce provincial government participation in the marketing system to encourage more competitive and aggressive marketing;
- to decrease financial risk to the British Columbia Petroleum Corporation;
- to provide more predictable netbacks to producers to revitalize the industry and to attract greater exploration activity; and
- to provide reasonable and predictable prices to British Columbia consumers.

1. Gas Royalty

a) Policy Intent

Prior to July 1, 1985, the vast majority of natural gas production in British Columbia was sold to the British Columbia Petroleum Corporation (BCPC) and was, as a result, exempt from direct royalty. Instead, the provincial "royalty" was derived from the difference between the price that the BCPC received from Westcoast Transmission, to which the gas was subsequently sold, and the price that the BCPC paid to producers. (See Appendix I, section D for a discussion of the pre-July 1, 1985, royalty regime.)

Under the post June 30, 1985, royalty regime, producers are able to negotiate directly with purchasers without the BCPC acting as intermediary. The majority of producers have, in fact, renegotiated their contracts with the BCPC and are subject to the gas royalties described below. Natural gas production from freehold lands is subject to the Mineral Land Tax.

In order to establish provincial jurisdiction over British Columbia's natural gas resource, the BCPC will take a temporary ownership position for all natural gas produced in the province. This is achieved through normal contractual arrangements between the BCPC and a producer, or by means of a "back-to-back" sale wherein the BCPC purchases gas from a producer and immediately resells it to that producer. (See Natural Gas Price Act, Bill 52-1985.)

b) Gas Royalty Formula

The natural gas and gas by-products royalty is dependent on four cost-related royalty factors (age, location, depth and production) and on a fifth price-related factor, termed the royalty rate adjustment factor (RRAF). (See Petroleum and Natural Gas Royalty Regulation 200/85, as amended.) A "maximum royalty rate" is calculated as the sum of the four cost-related factors. This maximum royalty rate is then multiplied by the RRAF to yield the effective royalty rate for production from a well.

The provincial government estimates that the maximum royalty rate applicable to natural gas and gas by-products produced before January 1, 1990, will not exceed 32 percent. The average maximum royalty rate, applicable to a well of average characteristics, is expected to be about 24 percent. Using these assumptions, average and marginal gas royalty rates with respect to price are presented in Figures 6.A.1 and 6.A.2, respectively, for various natural gas prices.

The royalty rate for natural gas or natural gas by-products, other than sulphur, produced in association with oil is 22 1/2 percent multiplied by the royalty rate adjustment factor, as mentioned above. The royalty rate applicable to sulphur is 16 2/3 percent. Field condensate from natural gas production is subject to new oil royalty rates.

Each of the cost-related factors and the price-related factor are discussed, in detail, below:

i) Age Factor

The age factor establishes four royalty percentages dependent on the elapsed time from the commencement of production. The elapsed time is measured in months during which the well was in production. There are two circumstances, however, in which elapsed time will not be measured from the commencement of production. For a gas well which commenced production between November 14, 1973, and December 31, 1977, the commencement of production is deemed to be December 31, 1977, for royalty purposes. Where production under a unit agreement is allocated to an undrilled spacing area, measurement commences from the later of the commencement of production and the date of unitization.

Months From Commencement of Production (Months)	Age Factor
0 to 48	4
49 to 96	6
97 to 144	8
over 144	20

Figure 6.A.1
BRITISH COLUMBIA
AVERAGE NATURAL GAS ROYALTY RATES

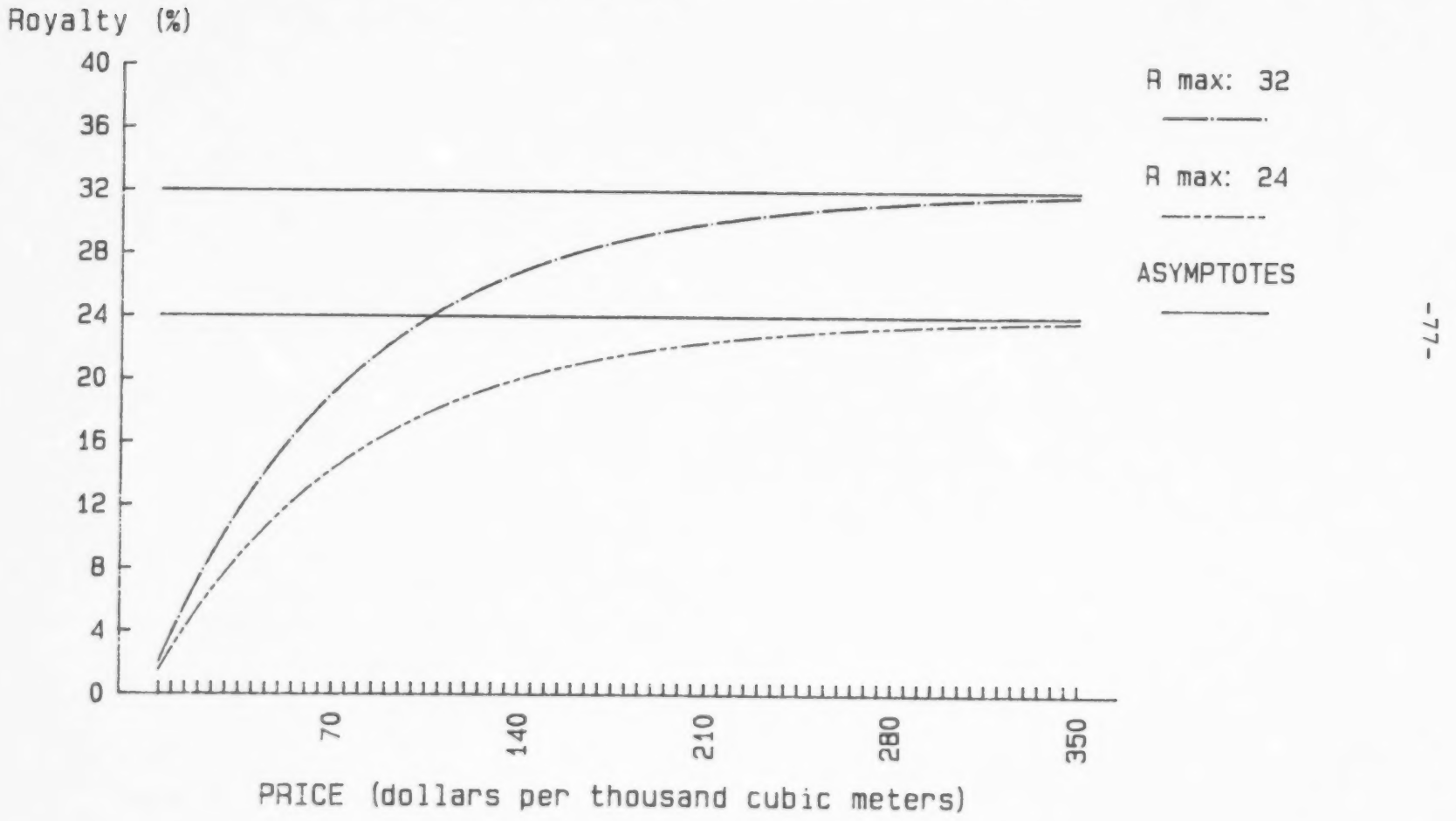
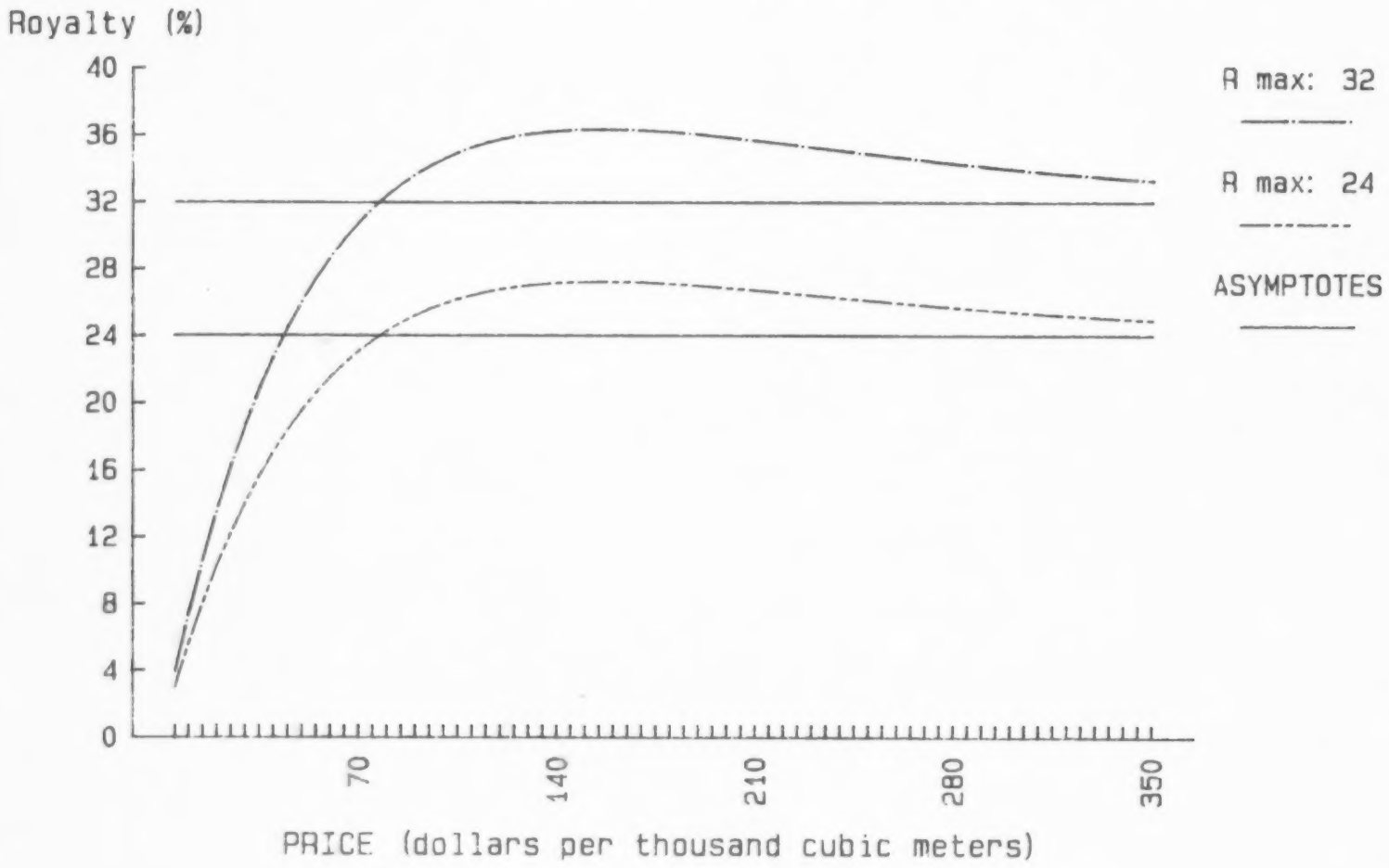


Figure 6.A.2
BRITISH COLUMBIA MARGINAL NATURAL GAS
ROYALTY RATES WITH RESPECT TO PRICE



ii) Location Factor

The location factor for a well is determined by the geographical location, defined by longitude and latitude, of the well within the province. Four areas and royalty rates are defined.

Location	Location Factor
Area A	7
Area B	6
Area C	5
Area D	4

iii) Depth Factor

The depth factor establishes four royalty rates corresponding to four depth ranges calculated in metres to the average depth of the base of the pool from which the well produces.

Average Depth to Base of Pool (metres)	Depth Factor
0 to 1,500	10
1,501 to 2,600	8
2,601 to 3,400	6
over 3,400	4

iv) Production Factor

The production factor establishes four royalty rates corresponding to four ranges of production based on the monthly production of a gas well, in thousand cubic metres.

Monthly Well Production ($10^3 m^3$)	Production Factor
0 to 300	0
301 to 900	2
901 to 1,800	4
over 1,800	7

v) Royalty Rate Adjustment Factor

As mentioned above, the RRAF is multiplied by the sum of the age, location, depth and production factors in order to obtain the effective average royalty rate for a well. The RRAF is given by the following equation:

$$RRAF = 1 - e^{-0.0129555\,P}$$

where: e is the natural logarithm; and

P is the price per thousand cubic metres, determined by dividing the value of the natural gas and gas by-products (other than sulphur) by the total production of those products.

2. Producer Cost Allowance

Allowances are provided to producers to cover the costs of field gathering and dehydration systems, field compression, and gas conservation. These producer cost allowances, established by the Minister, are deducted from the gas price in determining the amount of royalty payable on natural gas and gas by-products. The rate of the allowance depends on the geographical location of the equipment within the province. For this purpose, the province is divided into four areas corresponding to the areas for the location factor in the royalty formula. The rates currently in effect are:

	Location			
	Area A	Area B	Area C	Area D
	($/10^{3}m^3)			
Main Gathering and Dehydration Equipment	3.80	3.80	3.80	7.64
Field Compression	3.13	3.13	3.13	4.35
Gas Conservation	18.42	18.42	18.42	18.42

A deduction is also allowed for processing fees where the gas is custom processed by a third party. In situations in which the producer processes the gas himself, a producer cost allowance provides for a deduction in respect of notional processing fees. The allowance is determined by a formula identical to that used in the determination of the gas cost allowance in Alberta (see Chapter IV, subsection B.2).

C. INCENTIVES

1. Oil

Incremental production from an approved tertiary recovery pilot project is exempt from oil royalties. Tertiary projects other than pilot tertiary projects are subject to a royalty rate determined by agreement with the government, but will be limited to 50 percent of the new oil royalty rates during the pre-payout period for the project and the full new oil royalty rates after payout.

Also exempt from royalties is oil that, in the opinion of the Minister, was lost through no fault of the producer and for which the producer was not compensated; oil from an exploratory wildcat well completed after June 30, 1985, and that produces for no longer than three years; oil from a non-exploratory wildcat well completed after June 30, 1985, and that produces for no longer than two years; and a replacement well in an approved new or upgraded waterflood project where the well was completed after June 30, 1985, and produces for no longer than two years. A three-year royalty holiday is available for production from a new pool discovery well completed after June 30, 1974.

2. Natural Gas

Natural gas and gas by-products used in the drilling for or production of oil and gas are exempt from royalties. Also exempt are natural gas and gas by-products that, in the opinion of the Minister, were lost through no fault of the producer and for which the producer was not compensated.

D. CORPORATE INCOME TAX

The basic rate of corporate income tax in British Columbia is currently 16 percent. It will be reduced to 15 percent on January 1, 1987, and then to 14 percent on January 1, 1988. The small business tax rate will remain at its current 8 percent level over this period.

A royalty tax rebate is available by which Crown royalties in excess of the resource allowance are allowed to be deducted. Unused rebates, however, are not able to be carried over for use in other taxation years. Further, where the resource allowance exceeds the disallowed Crown royalty, a surcharge is levied equal to the difference times the applicable tax rate. Therefore, in a situation where no royalty is paid, such as for a tertiary recovery pilot project, there is effectively no resource allowance provided; the taxpayer pays the full 16 percent rate. (See Income Tax Act, R.S.B.C. 1979, c. 190, as amended.)

A tax of 0.2 of one percent of paid-up capital is currently levied on corporations in British Columbia but will generally be phased out for taxation years ending after 1986. (See Corporation Capital Tax Act, R.S.B.C. 1979, c. 69, as amended.)

CHAPTER VII
OTHER PROVINCIAL FISCAL REGIMES

A. MANITOBA

1. Royalties

Two classifications of oil exist in Manitoba for royalty purposes: old oil and new oil. Old oil is produced from wells completed prior to April 1, 1974. New oil is produced from wells completed after March 31, 1974, or from wells abandoned prior to that date and subsequently re-entered.

Incremental production from the use of an enhanced oil recovery scheme commencing operation after December 31, 1978, is also defined as new oil for royalty purposes. Further, the Minister may designate any oil production as new oil. (See The Crown Petroleum Royalty Regulation 149/84 under The Mines Act, R.S.M. 1970, c. M160, as amended.)

Manitoba produces approximately three-quarters of one percent of the total Canadian production of oil. No natural gas is produced in the province. Should natural gas production commence, however, the royalty rate would be 12 1/2 percent.

The royalty formulae for old oil in Manitoba are as follows:

$R(m^3) = Q^2/265$, if monthly production, Q, is less than 50 cubic metres; and

$R(m^3) = 9.43 + 0.45\ (Q-50)$, if monthly production, Q, is equal to or greater than 50 cubic metres.

The royalty is dependent on well productivity but not on price.

New oil is subject to a royalty equal to 55 percent of the old oil royalty, except for new oil produced from or deemed to be produced from a new oil well during the royalty incentive period (defined below) for that well.

Incentives in the form of reduced royalties are available for production from new oil wells drilled and completed over the period January 1, 1979, to December 31, 1986. The royalty incentive period in months, RIP, is based on the total depth of the new oil well in metres, TD, and is determined by the formula:

$$RIP = 12 + (TD - 600)/30$$

For example, a well drilled to a depth of 2100 metres during the qualifying period would be eligible for a royalty reduction for its first 62 months of production. During the RIP, the royalty is calculated as 35 percent of the corresponding old oil royalty.

2. Freehold Taxes

Production of oil from freehold lands in Manitoba accounts for approximately 80 percent of the provincial output. Freehold taxes on oil and gas are applied by means of a mill rate per dollar of an assessed value based on production. The "assessed value" is one and one-half times the wellhead value received for the production. The tax rate for gas is 8 mills on each dollar of assessed value or 1.2 percent of the wellhead value. For old oil, tax rates range from 0.9 percent of wellhead value for a well producing 20 cubic metres per month to a maximum 41.25 percent of wellhead value for a well producing 1000 cubic metres per month. There is no tax for monthly production of less than 20 cubic metres.

New oil, as defined above, qualifies for a preferential rate. There is no tax on a well producing less than 35 cubic metres per month, and a maximum rate of 18.75 percent of wellhead value on monthly production of 900 cubic metres. Determined according to the RIP formula for Crown oil, the production incentive period for freehold oil provides a reduced tax on freehold production from new oil wells completed between January 1, 1979, and December 31, 1986. The tax free production level is up to 55 cubic metres per month, and the maximum tax rate is 8.7 percent of wellhead value. (See The Oil and Natural Gas Tax Act, R.S.M., c. O 35, as amended.)

3. Corporate Income Tax

The basic rate of corporate income tax in Manitoba is 16 percent. There is a reduction of 6 percent for qualifying small businesses. Manitoba does not provide any form of royalty tax rebate to corporations. Individuals, however, are entitled to a rebate, in respect of freehold taxes, calculated on the amount by which a taxpayer's taxable income exceeds his "revised taxable income". Revised taxable income is defined as a taxpayer's taxable income plus any resource allowance minus any tax paid in the year under The Oil and Natural Gas Tax Act. (See The Income Tax Act (Manitoba), R.S.M. 1970, c. I 10, as amended.)

A tax of 0.2 of one percent of paid-up capital is levied on corporations in Manitoba. (See The Corporation Capital Tax Act, S.M. 1976, c. 68/C 226, as amended.)

B. NEWFOUNDLAND

1. Royalties

The Government of Newfoundland and Labrador and the Government of Canada announced the Atlantic Accord on February 11, 1985. The Atlantic Accord is a comprehensive agreement on offshore oil and gas resource management and revenue sharing.

Under the Accord, the Government of Newfoundland and Labrador is allowed to establish and collect resource revenues and provincial taxes of general application as if the offshore petroleum-related activities were located on land within the province. Such fiscal instruments include:

i) royalties;
ii) bonus payments;
iii) rental and licence fees;
iv) corporate income tax, which is the same as that generally prevailing in the province;
v) sales tax, which is the same as that generally prevailing in the province; and
vi) other forms of resource revenue and provincial taxes of general application, consistent with the spirit of the Accord.

The provincial government is currently in the process of establishing a royalty regime, which will be applicable to the offshore area.

2. Corporate Income Tax

The basic tax rate in Newfoundland is 16 percent. There is a reduction of 6 percent for qualifying small businesses. (See The Income Tax Act, R.S. Nfld. 1970, c. 163, as amended.)

C. NOVA SCOTIA

The Government of Nova Scotia and the Government of Canada signed a Memorandum of Agreement on March 2, 1982 regarding offshore oil and gas resource management and revenue sharing. The Agreement results in two areas of jurisdiction in Nova Scotia: the offshore region and the onshore region. (See Canada-Nova Scotia Oil and Gas Agreement Act, S.C. 1983-84, c. 29.)

It should also be noted that the 1982 Agreement is currently being renegotiated. A new agreement on offshore resource management and revenue sharing will provide terms similar to those contained in the Atlantic Accord (see subsection B.1).

1. Offshore Region

Under the 1982 Agreement, which is subject to review five years after production commences and every five years thereafter, Nova Scotia and the federal government will share future revenues from offshore production (such as from the Venture gas field off Sable Island). Revenues subject to sharing include:

i) the proceeds of royalties;
ii) revenues that would have accrued under provincial corporate income tax if the offshore area were part of Nova Scotia;
iii) revenues that would have been generated by Nova Scotia retail sales tax had the offshore region been in the province;
iv) the proceeds of any bonus payments; and
v) the proceeds of any rentals and license fees in excess of offshore administration costs.

The Nova Scotia share is determined on the basis of complex criteria relating to fiscal capacity and the unemployment rate. All revenues are to be collected as specified in the appropriate federal legislation and credited to a fund from which Nova Scotia's share will be automatically disbursed.

2. Onshore Region

The petroleum royalty system for the onshore area of Nova Scotia is governed by provincial legislation. Both oil and natural gas are subject to a 10 percent royalty. A two-year royalty holiday is granted for production from the first lease on land subject to an exploration agreement. A gas cost allowance, determined by the Minister, is also available to account for the costs of gas processing. (See Petroleum Resources Act, S.N.S. 1980, c. 12, as amended, and Regulation 85-1180.)

3. Corporate Income Tax

The basic rate of corporate income tax in Nova Scotia is 15 percent. It is reduced by 5 percent for qualifying small businesses. Qualifying small businesses incorporated after April 18, 1986, will also be eligible for an income tax holiday for their first two taxation years. (See Income Tax Act, R.S.N.S. 1967, c. 134, as amended.)

D. ONTARIO

1. Royalties

The majority of land in Ontario is freehold and any royalties are a matter of private agreement between the freehold owner and the producer. On average, both oil and gas produced on freehold lands are subject to a royalty of approximately 12 1/2 percent of gross production.

Production from provincial Crown lands would be subject to a combination of land rental rates, bonuses and royalties. Natural gas produced in Lake Erie is subject to a gross royalty of 12 1/2 percent. (See Regulation 634 under the Mining Act, R.S.O. 1980, c. 268, as amended.) Oil royalty rates, however, are not indicated presumably because oil is not currently being produced from Crown lands in the province.

2. Corporate Income Tax

The basic rate of corporate income tax in Ontario is 15 1/2 percent. There is a 1 percent reduction for firms in specified manufacturing and processing activities, and mining (other than oil sands mining), logging, farming and fishing activities. In addition, firms qualifying for the small business deduction are eligible for a further 4 1/2 percent reduction. Qualifying small businesses incorporated after May 13, 1982, are also eligible for an income tax holiday, for taxation years ending after May 13, 1985, where the taxation year is their first, second or third taxation year. Ontario offers no form of royalty tax rebate. A tax of 0.3 of one percent of paid-up capital is also levied on corporations in Ontario. (See Corporations Tax Act, R.S.O. 1980, c. 97, as amended.)

It is important to note that Ontario corporate income tax rules have not always paralleled federal rules as the latter have applied to capital cost allowances, the resource allowance, exploration and development expenditures and depletion. For example, capital assets acquired prior to October 25, 1985, were eligible for full capital cost allowances in the year of acquisition for provincial income tax purposes. Ontario rules, however, now follow federal half-year rules for capital assets acquired after October 24, 1985.

E. QUEBEC

1. Royalties

The royalty payable to the province on the wellhead value of crude oil and natural gas production is determined as follows (see Mining Act, R.S.Q., c. M-13):

	Average Daily Production	Royalty
Oil (m^3)	0 to 7	0.05 (Production)
	8 to 30	0.35 + 0.1 (Production - 7)
	over 30	2.63 + 0.125 (Production - 30)
Natural Gas (10^3m^3)	0 to 84	0.1 (Production)
	over 84	8.4 + 0.125 (Production - 84)

Oil is not currently being produced in the province. Natural gas is being produced from only one well.

2. Corporate Income Tax

The basic rate of corporate income tax in Quebec is 13 percent. There is a reduction of 7.5 percent for active business corporations and a further 2.5 percent reduction for corporations that qualify for the federal small business deduction. As is the case with Ontario, Quebec offers no form of royalty tax rebate but the 25 percent resource allowance is available. (See Taxation Act, R.S.Q., C.I-3, as amended, and Taxation Act Regulations.)

Quebec effectively provides two depletion systems: one for corporations and one for individuals. An earned depletion allowance similar to the federal allowance is available for corporations. An additional depletion allowance is also provided which differs for corporations and individuals dependent on the nature, location and timing of the eligible expenditures.

A corporation may claim the earned depletion allowance to an annual maximum of 25 percent of resource profits. As in the federal depletion system, CDE incurred in respect of a qualified tertiary oil recovery project, well equipment used in a qualified tertiary oil recovery project, heavy crude oil upgrading assets and oil sands assets are eligible to earn depletion at the rate of 33 1/3 percent.

Corporations are eligible to earn the additional allowance on exploration and development expenses incurred in Quebec, and on the costs of primary recovery equipment incurred anywhere in Canada at a rate of 50 percent. The allowance is deductible to an annual maximum of 50 percent of income from any source.

Individuals may earn the additional allowance at a rate of 66 2/3 percent on exploration expenses incurred in Quebec between April 1, 1980, and December 31, 1987. The allowance is deductible to an annual maximum of income from any source.

A tax of 0.45 of one percent of its paid-up capital is levied, in general, on corporations in Quebec. Further, corporations which refine petroleum within the province, or have an establishment in Quebec and refine oil outside of Quebec must pay an additional tax equal to 1 percent of their paid-up capital.

PART III. OTHER ROYALTY AND INCENTIVE SYSTEMS

OVERVIEW

On October 30, 1985, the Government of Canada announced a new frontier energy policy, which is to be contained in a new act entitled "The Canada Petroleum Resources Act". A 1/5/30 percent royalty will replace the former 10 percent basic royalty and 40 percent Progressive Incremental Royalty of the Canada Oil and Gas Act. Two new incentives will also be introduced: the exploration tax credit (ETC) and the investment royalty credit (IRC). The ETC, which is also applicable to eligible expenditures incurred on provincial lands, is outlined in Chapter I, subsection C.3. The new frontier royalty and the IRC are described in Chapter VIII.

The royalty regime applicable to oil and natural gas production from Indian lands is discussed in Chapter IX.

CHAPTER VIII
FRONTIER LANDS

A. ROYALTIES

A 1/5/30 percent royalty regime will apply to production from frontier regions where the responsibility for establishing royalties has not been transferred to a province. Prior to project "payout", the royalty will commence at a rate of 1 percent of gross revenues, rising to 5 percent in increments of 1 percent every 18 months. Following payout of the initial investment, the royalty will equal the larger of 5 percent of gross revenues or 30 percent of net cash flow. The terms "project payout" and "net cash flow" will be determined through consultations with the industry, and provincial and territorial governments. This royalty regime is similar to the royalties levied by Alberta on high-cost oil sands and enhanced oil recovery projects in that province.

The policy intent of the new royalty regime is to limit the royalty burden during early production and on marginal projects, but to ensure an equitable sharing of revenues between government and industry after the initial investment has been recovered. (See Government of Canada, News Release 85/160, "Government Introduces New Frontier Energy Policy".)

B. INVESTMENT ROYALTY CREDIT

The investment royalty credit will be earned, at the rate of 25 percent, on eligible exploration well costs, up to $5 million per well, incurred in respect of new exploration wells on the frontier lands. The credit will be applied against royalties otherwise payable within a region. (See Government of Canada, News Release 85/160, "Government Introduces New Frontier Energy Policy".)

CHAPTER IX
INDIAN LANDS

Oil and gas under an Indian reservation are the property of the band. However, Indian and Northern Affairs administers the oil and gas rights as trustees for various bands and collects royalties on their behalf. (See the Indian Oil and Gas Act and Regulations.) As previously mentioned, these royalty payments are deductible in calculating federal taxable income.

A. OIL ROYALTY

Except as otherwise provided in a special agreement, the oil royalty on Indian Lands is composed of a basic royalty and a supplementary royalty. All oil is deemed to be new for the first five years of production. The basic new oil royalty is dependent on well productivity as follows:

Production (m^3/month)	Royalty (m^3)
0 to 80	0.1 (Production)
81 to 160	8 + 0.2 (Production - 80)
over 160	24 + 0.26 (Production - 160)

There is also a supplementary royalty calculated using the formula:

$$S = (\text{Production} - B)\ (0.50\ (P - R))$$

where: S is the supplementary royalty;
B is the basic royalty;
P is the actual selling price; and
R is the reference price, which is the posted price per barrel as of January 1, 1974, or an equivalent reference price specified in writing for that field by the Manager.

For oil which is old (i.e., from a well producing for more than five years) the basic royalty, B, is identical except for higher productivity wells. Wells producing in excess of 795 cubic metres per month pay a royalty, in cubic metres, equal to:

$$B = 189 + 0.4 \text{ (Production - 795)}$$

The supplementary royalty on old oil is calculated using the formula:

$$S = \text{(Production - B) } (0.75 \text{ (P - R - \$12.58) + \$6.29)}$$

where the factors have the same definition as above.

B. NATURAL GAS ROYALTY

As in the case of the oil royalty, the natural gas royalty on Indian lands, except as otherwise provided in a special agreement, is composed of a basic royalty and a supplementary royalty. In general, no deductions are allowed. The basic royalty is calculated as 25 percent of production while the supplementary royalty is individually determined for each of the component gas products. The supplementary royalty formulae for natural gas, pentanes plus and sulphur are shown in the following table.

Supplementary Royalty Formulae

	Selling Price (P)	Royalty
Natural Gas ($/10^{3}m^3)	10.65 - 24.85	0.75 (0.3 (P-10.65))
	over 24.85	0.75 (4.26 + 0.55 (P-24.85))
Pentanes Plus ($/m^3)	over 27.68	0.75 (0.5(P-27.68))
Sulphur ($/tonne)	over 39.37	0.75 (0.5(P-39.37))

PART IV. DOWNSTREAM TAXES

OVERVIEW

Federal and provincial sales taxes, and the federal excise tax on motive fuels and other petroleum products are described in this part. Motive fuels include gasoline, aviation gasoline, diesel fuel, jet fuel, and propane.

CHAPTER X
FEDERAL SALES AND EXCISE TAXES

A. SALES TAX

The federal sales tax applies generally to most goods including petroleum products and gasoline (home heating fuels and natural gas are exempted) and is payable by manufacturers. The federal sales tax rate was increased to 12 percent from 11 percent on April 1, 1986, as a result of the February 26, 1986, federal budget. The rate was originally to be increased to 10 percent from its previous 9 percent level for the period October 1, 1984, to December 31, 1988, in order to help finance the costs of the Special Recovery Program announced in the April 19, 1983, budget. As a result of the May 23, 1985, budget, however, the sales tax rate was increased to 11 percent, effective January 1, 1986, and the former December 31, 1988, termination date was cancelled. (See Excise Tax Act, Part V, section 27.)

A change in the method of computing sales tax for gasoline and diesel fuel was announced in the May 23, 1985, budget. In order to relieve industry concern that the sales tax may not apply uniformly to sales of gasoline and diesel fuel through independent dealers, wholesalers and refinery-owned retail outlets, and to relieve administrative difficulties in determining the amount of the liability when fuel prices fluctuate rapidly, the sales tax is now expressed as a specific amount per litre of the fuels, effective June 1, 1985. These amounts are adjusted quarterly, based on the Industrial Product Price Index for motor gasoline and for diesel fuel published by Statistics Canada. Adjustments to the specific levies are made quarterly, on the first day of January, April, July and October of each year, commencing on October 1, 1985. The specific amounts applicable for the period April 1, 1986, to June 30, 1986, are:

- 3.98 cents per litre for regular, leaded gasoline;
- 4.36 cents per litre for regular, unleaded gasoline;
- 4.48 cents per litre for premium gasoline; and
- 3.66 cents per litre for diesel fuel.

Farmers, fishermen, loggers and mine operators are eligible for a rebate of sales tax on purchases of gasoline and diesel fuel for off-highway use in commercial activities. Effective December 1, 1984, the rebate equals 3 cents per litre for fishermen, loggers and mine operators to the end of 1987, and for farmers to April 30, 1986. The rebate for farmers will be increased to 3.5 cents per litre for the period May 1, 1986, to December 31, 1987. (See Department of Finance Canada, Release 86-81, "Details of Tax Relief for Farmers and Oil Producers Announced".)

Federal sales tax is also payable by manufacturers and producers of propane gas on 17 percent of their sales. This percentage was established, effective April 1, 1984, as a reasonable estimate of the portion of propane used under taxable conditions, i.e., as a fuel for internal combustion engines.

B. EXCISE TAX

The federal excise tax is imposed at the manufacturing level at the specific tax rate of 3.5 cents per litre on gasoline and aviation gasoline, and at the rate of 2.0 cents per litre on diesel and jet fuel. A 1.0 cent per litre increase in the excise tax rates on these fuels is scheduled for January 1, 1987.

Commercial users of gasoline and aviation gasoline, as well as certain other taxpayers (e.g., clergy and handicapped persons) are, however, eligible for a 1.5 cents per litre refund of the excise tax. (Prior to September 3, 1985, the excise tax rate equalled 1.5 cents per litre and applied only to non-commercial users of gasoline and aviation gasoline.) For the period May 1, 1986, to December 31, 1986, farmers will also be eligible for an additional 2.0 cents per litre excise tax rebate on purchases of gasoline and a 2.0 cents per litre rebate on purchases of diesel fuel, for off-highway farm use. For the period January 1, 1987, to December 31, 1987, the rebate for farmers will rise to 3.0 cents per litre on purchases of these fuels. (See Department of Finance Canada, Release 86-81, "Details of Tax Relief for Farmers and Oil Producers Announced".)

CHAPTER XI
PROVINCIAL SALES TAXES

All provinces except Alberta and Saskatchewan impose some form of motive fuel or retail sales tax on gasoline and petroleum products. Exemptions vary from province to province although most provinces exempt home heating oil. The following table shows the provincial ad valorem tax rates currently in effect for gasoline and diesel fuel.

Provincial Tax Rates (%)

Provinces	Gasoline	Diesel
Newfoundland	22	26
P.E.I.	20	23
Nova Scotia	20	21
New Brunswick	20	23
Quebec[1]	30	30
Ontario[2]	Fixed	Fixed
Manitoba[3]	Fixed	Fixed
Saskatchewan	None	None
Alberta	None	None
B.C.	20	20
Yukon[4]	Fixed	Fixed
N.W.T.	15	12.75

Notes:
1. Reduced by one-third within 5 kilometres of the provincial border.
2. Effective January 1, 1986, this is a fixed tax rate of 8.3 cents per litre for gasoline and 9.9 cents per litre for diesel fuel.
3. This is currently a fixed tax rate of 8.9 cents per litre for leaded gasoline; 8.0 cents per litre for unleaded gasoline; and 9.2 cents per litre for diesel fuel.
4. This is currently a fixed tax rate of 4.2 cents per litre for gasoline and 5.2 cents per litre for diesel fuel.

APPENDIX I
HISTORICAL FISCAL CHANGES

A. FEDERAL FISCAL CHANGES

A chronology of federal fiscal instruments applicable to petroleum over the period 1974-90 is provided in Table A.1. Included is a history of both upstream and downstream fiscal changes. A brief discussion of selected federal fiscal changes is provided below.

1. Corporate Income Tax

a) Federal Royalty Deductibility

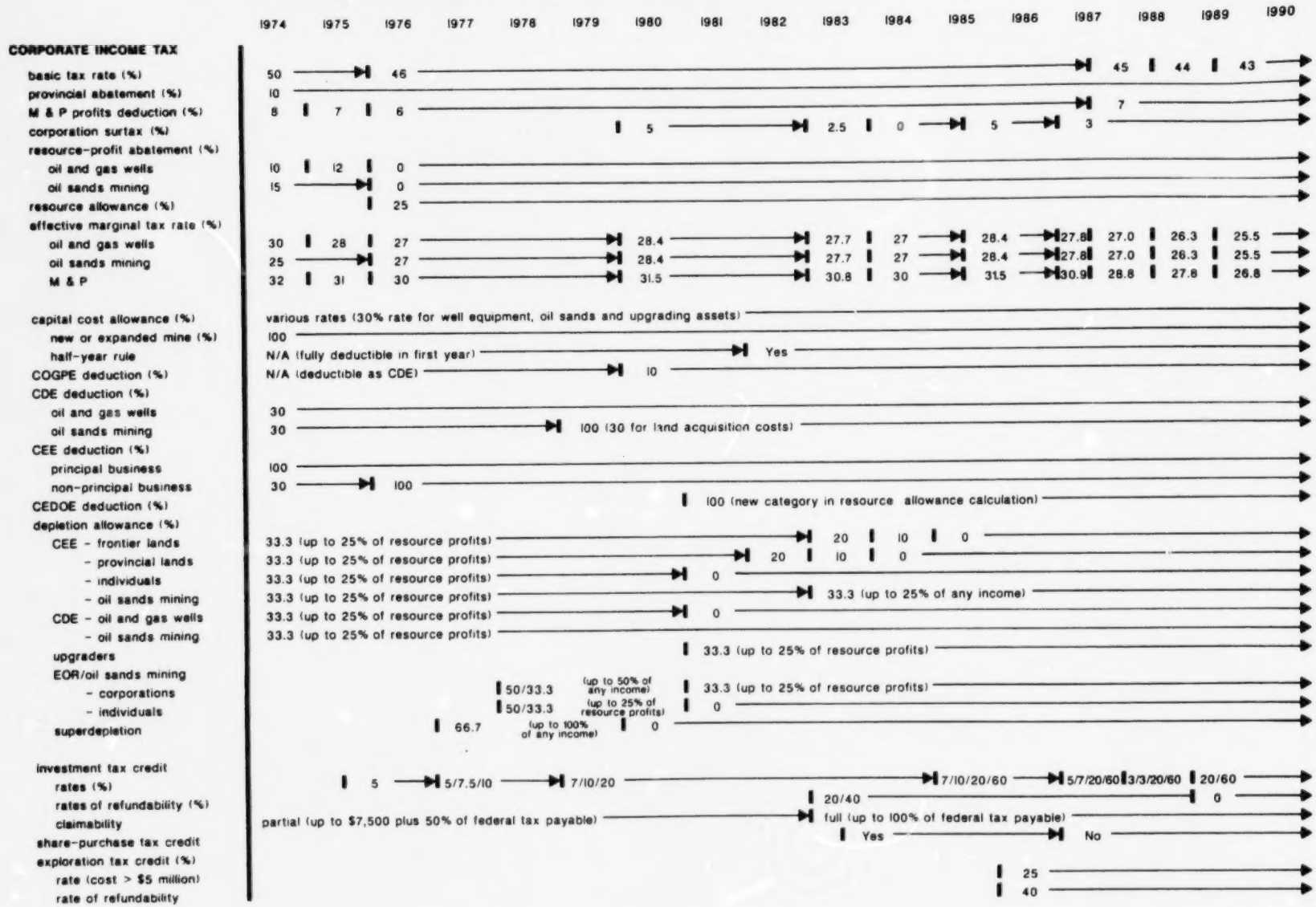
Prior to May 6, 1974, royalties payable to the Crown in right of a province were deductible from income for federal income tax purposes as an expense of earning income. Alternatively, they would never have been included in gross income in the first place. In 1974, the Income Tax Act was amended to disallow the deduction (paragraph 18(1)(m)) or to include the royalty in income (paragraph 12(1)(o)), as the situation may dictate. These rules were introduced in reaction to substantial increases in provincial royalties on oil and gas which shifted a significant portion of the government share of resource development profits from the federal government to the provincial governments.

b) Frontier Exploration Allowance (Super Depletion)

From April 1, 1977, to March 31, 1980, frontier exploration costs in excess of $5 million on a single well earned extra depletion at a rate of 66 2/3 percent. This super depletion was not restricted to the 25 percent resource profits ceiling for earned depletion purposes, but was deductible to the extent of income from any source. Thus, for each dollar spent in excess of $5 million on a single well, a taxpayer earned a combined depletion allowance of one dollar in addition to the standard CEE write-off. (See ITR 1207.)

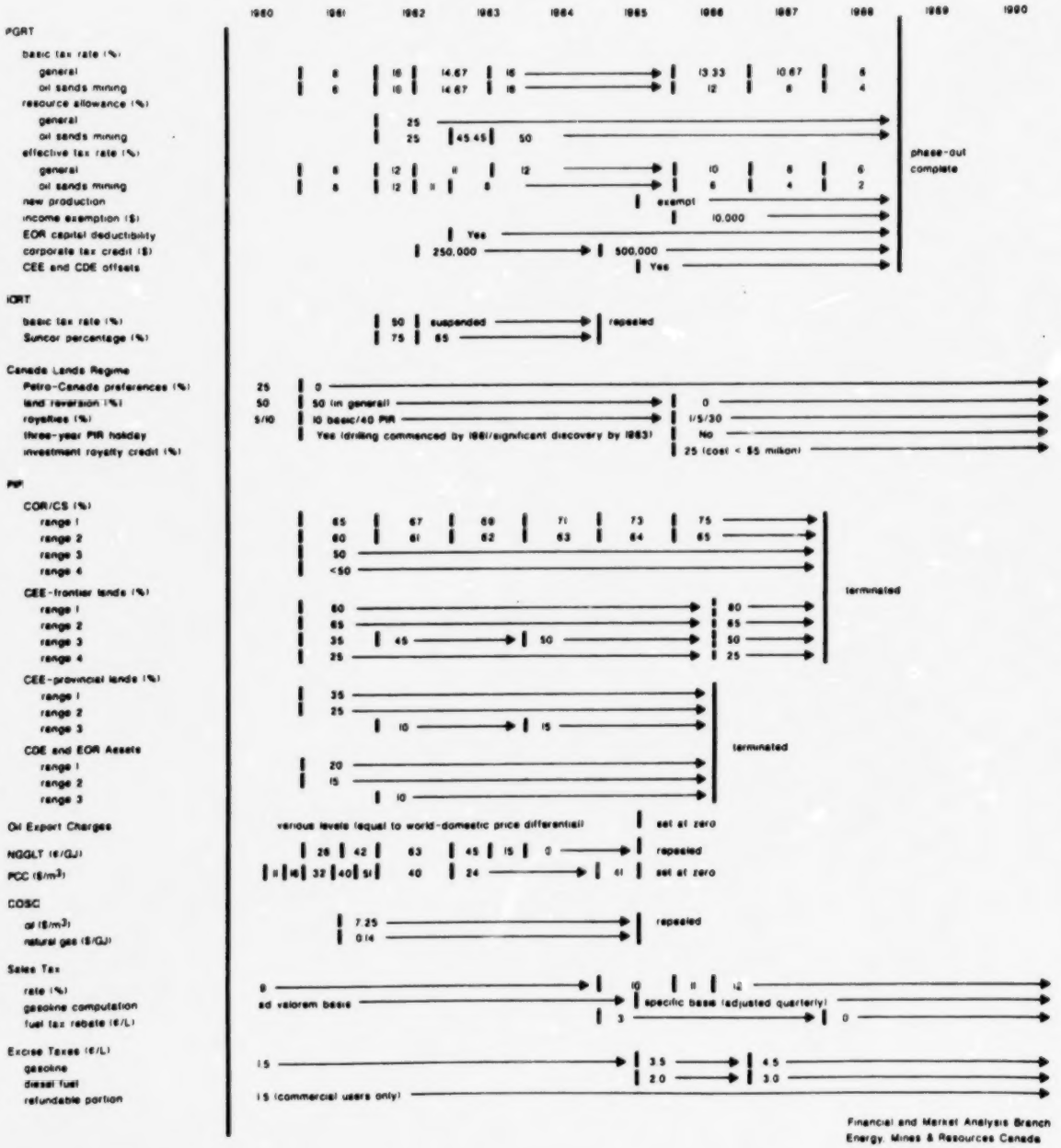
Table A-1

Chronology of Federal Fiscal Instruments Applicable to Petroleum: A Summary


1974 1975 1976 1977 1978 1979 1980 1981 1982 1983 1984 1985 1986 1987 1988 1989 1990
CORPORATE INCOME TAX
basic tax rate (%)
provincial abatement (%)
M & P profits deduction (%)
corporation surtax (%)
resource-profit abatement (%)
oil and gas wells
oil sands mining
resource allowance (%)
effective marginal tax rate (%)
oil and gas wells
oil sands mining
M & P
capital cost allowance (%)
new or expanded mine (%)
half-year rule
COGPE deduction (%)
CDE deduction (%)
oil and gas wells
oil sands mining
CEE deduction (%)
principal business
non-principal business
CEDOE deduction (%)
depletion allowance (%)
CEE - frontier lands
- provincial lands
- individuals
- oil sands mining
CDE - oil and gas wells
- oil sands mining
upgraders
EOR/oil sands mining
- corporations
- individuals
superdepletion
investment tax credit
rates (%)
rates of refundability (%)
claimability
share-purchase tax credit
exploration tax credit (%)
rate (cost > $5 million)
rate of refundability
50 46 45 44 43
10
8 7 6 7
5 2.5 0 5 3
10 12 0
15 0
25
30 28 27 28.4 27.7 27 28.4 27.8 27.0 26.3 25.5
25 27 28.4 27.7 27 28.4 27.8 27.0 26.3 25.5
32 31 30 31.5 30.8 30 31.5 30.9 28.8 27.8 26.8
various rates (30% rate for well equipment, oil sands and upgrading assets)
100
N/A (fully deductible in first year) Yes
N/A (deductible as CDE) 10
30
30 100 (30 for land acquisition costs)
100
30 100
100 (new category in resource allowance calculation)
33.3 (up to 25% of resource profits) 20 10 0
33.3 (up to 25% of resource profits) 20 10 0
33.3 (up to 25% of resource profits) 0
33.3 (up to 25% of resource profits) 33.3 (up to 25% of any income)
33.3 (up to 25% of resource profits) 0
33.3 (up to 25% of resource profits)
33.3 (up to 25% of resource profits)
50/33.3 (up to 50% of any income) 33.3 (up to 25% of resource profits)
50/33.3 (up to 25% of resource profits) 0
66.7 (up to 100% of any income) 0
5 5/7.5/10 7/10/20 7/10/20/60 5/7/20/60 3/3/20/60 20/60
20/40 0
partial (up to $7,500 plus 50% of federal tax payable) full (up to 100% of federal tax payable)
Yes No
25
40

Financial and Market Analysis Branch
Energy, Mines and Resources Canada
March 1, 1986

Chronology of Federal Fiscal Instruments Applicable To Petroleum: A Summary (continued)



Financial and Market Analysis Branch
Energy, Mines & Resources Canada
March 1, 1986

c) Supplementary Depletion

Between April 10, 1978, and December 31, 1980, qualifying expenditures on depreciable assets (Class 10(j)) used in enhanced recovery projects and expenditures on oil sands plants (Class 28) were eligible to earn a supplementary depletion allowance at the rates of 50 percent and 33 1/3 percent, respectively. For corporations, the allowance was deductible up to the lesser of their supplementary depletion base and 50 percent of income from any source. Non-corporate taxpayers were allowed to deduct the allowance up to the lesser of their supplementary depletion base and 25 percent of resource profits. (See ITR 1212.)

2. Incremental Oil Revenue Tax

The Incremental Oil Revenue Tax (IORT) was applicable to old oil discovered before 1981, and equalled 50 percent of the difference between the amount received for the oil and a base price. The base price approximated the price that would have been received had the NEP prices prevailed. The only deduction permitted was for the average incremental royalty paid on production. A special low productivity well allowance (LPWA) reduced the IORT on oil from wells producing less than 3.18 cubic metres per day. Revenue that was subject to the IORT was not subject to income tax. (See Division I of the PGRT Act.)

The IORT was introduced on January 1, 1982, but was suspended for most producers for the period June 1, 1982, to December 31, 1984. Despite the two-year suspension, Suncor Inc. (formerly Great Canadian Oil Sands Limited) continued to pay the tax, until December 31, 1984, on 65 percent of its synthetic oil production as part of an agreement whereby it was allowed to receive the New Oil Reference Price (NORP) on all of its synthetic output (see PGRT Regulations, section 4.1). Norcen International Ltd., which has a royalty interest in Suncor's oil sands production, also continued to pay the Incremental Resource Royalty Tax (IRRT) on its royalty income from the operation over the same period. The IRRT was imposed under Division II of the PGRT Act. The IORT and IRRT were repealed for all taxpayers on January 1, 1985, as a result of the Western Accord.

3. Petroleum Compensation Charge

The Petroleum Compensation Charge (PCC) was levied on all crude oil refined or consumed in Canada, and on oil products imported into Canada from July 12, 1980, to May 31, 1985. Exports of crude oil and oil products were, however, exempt from the charge. Revenue from the PCC was dedicated to subsidizing the higher costs of new domestic oil and oil imports. Under the 1981 Canada-Alberta Memorandum of Agreement, Canada agreed not to run a surplus of PCC revenues over the 1981-86 period. The PCC rate was to be changed as needed to balance revenues and expenditures in the PCC account. In fact, however, a deficit of over $1 billion existed in the PCC account when the charge was terminated on June 1, 1985. It was agreed in the Western Accord that the federal government would not introduce any special tax on the oil and gas industry in order to recover this deficit. (See Energy Administration Act, Part III.1.)

Rates of PCC over the period July 12, 1980, to May 31, 1985, are given below:

	PCC Rate[1] ($/m^3)
July 12, 1980	11.01
November 1, 1980	16.04
January 1, 1981	31.77
June 3, 1981	39.64
September 22, 1981	51.28
November 30, 1981	39.64
January 1, 1983	23.64
November 10, 1984	41.14
June 1, 1985	0.00

Note: 1. Farmers, fishermen, loggers and mine operators were eligible for a PCC rebate of 1.8 cents per litre on purchases of gasoline and diesel fuel for off-highway use in commercial activities. The rebate was available for the period December 1, 1984, to May 31, 1985. Relief from the November 10, 1984, PCC increase was also extended to producers of oil-based petrochemical feedstocks from November 10, 1984, to May 31, 1985.

4. Canadian Ownership Special Charge

The Canadian Ownership Special Charge (COSC) was levied on all domestically consumed natural gas, natural gas liquids and crude oil from May 1, 1981, to May 31, 1985. It was imposed at the processing plant stage in the case of natural gas and gas liquids, and at the refinery stage for crude oil. The revenue from the COSC originally went toward financing Petro-Canada's acquisition of Petrofina, which was completed in March 1983. Subsequently, COSC revenues were used to subsidize increases in natural gas transmission tolls in excess of 5 percent of June 30, 1983, levels. (See Energy Administration Act, Part III.2.)

The rates of tax over the period May 1, 1981, to May 31, 1985, were as follows:

	COSC Rates[1]
Crude Oil ($/m^3)	7.25
Natural Gas ($/GJ)	0.14
Ethane ($/m^3)	2.60
Propane ($/m^3)	3.55
Butane ($/m^3)	3.95

Note: 1. Exports of natural gas and natural gas liquids were not subject to the COSC.

5. Natural Gas and Gas Liquids Tax

The Natural Gas and Gas Liquids Tax (NGGLT), originally introduced in the National Energy Program, was eliminated effective June 1, 1985, as a result of the Western Accord. The tax rate had been set to zero effective February 1, 1984. The NGGLT was imposed on marketable pipeline gas consumed in Canada, on gas from the Canada Lands whether it was consumed domestically or exported, and on certain gas liquids which were either consumed within Canada or

exported. Wells which produced less than 1000 gigajoules of gas in a calendar year and that were not part of a business of producing, distributing or processing gas were exempt from the tax. (See Excise Tax Act, Part IV.1.)

Rates of NGGLT over the period November 1, 1980, to February 1, 1984, are given below:

NGGLT Rates

	Natural Gas ($/GJ)	Ethane ($/m^3)	Propane ($/m^3)	Butane ($/m^3)
November 1, 1980	0.28	5.18	7.11	7.93
July 1, 1981	0.42	7.76	10.66	11.90
February 1, 1982	0.63	11.65	16.00	17.85
February 1, 1983	0.45	8.33	11.44	12.77
August 1, 1983	0.15	2.78	3.81	4.25
February 1, 1984	0.00	0.00	0.00	0.00

Notes:
1. The NGGLT became effective February 1, 1981, for exports of natural gas but was reduced to a zero rate, on October 1, 1981, for gas originating in an agreeing province.
2. From October 1, 1981, the federal government refunded the NGGLT on exports of ethane originating in an agreeing province.

6. Oil Export Charges

Oil export charges were levied on the bulk export of crude oil and refined petroleum products from October 1, 1973, to May 31, 1985. Initially imposed under Part III.1 of the Excise Tax Act and called the oil export tax, it was renamed the oil export charge and imposed under the Petroleum Administration Act on April 1, 1974. The latter Act was subsequently renamed the Energy Administration Act.

The export charges essentially equalled the difference between prevailing domestic prices (plus transportation costs to the export market) and the prices prevailing in markets in the United States. Revenues from the charges were shared equally between the federal government and the producing provinces over the periods October 1, 1973 to March 31, 1974, and November 1, 1980, to May 31, 1985. Oil products exported from Quebec and the Atlantic provinces were deemed to be derived from imported crude and, therefore, oil import compensation was repaid.

B. ALBERTA FISCAL CHANGES

1. Pre-June 1, 1985, Oil Royalty Classification

Prior to crude oil price deregulation on June 1, 1985, oil classification for royalty purposes roughly corresponded to oil classification for pricing purposes. For royalty purposes, oil was classified as either old oil or NORP oil over the period July 1, 1983, to May 31, 1985. The definition of NORP oil was identical to the current definition of new oil. Under the June 30, 1983, Amending Agreement between Canada and Alberta, oil from pools discovered after March 31, 1974, and oil produced from all new infill wells drilled within a pre-NORP oil entity after June 30, 1983, received the NORP.

From January 1, 1982, to June 30, 1983, three categories of oil existed for royalty purposes: old oil, new oil and NORP oil. New oil consisted of oil from pools discovered between April 1, 1974, and December 31, 1980, and incremental production from a waterflood or equivalent scheme initiated after April 1, 1974. New oil was eligible to receive the Special Old Oil Price (SOOP) after June 30, 1982. NORP oil was from pools discovered after December 31, 1980, and was eligible to receive the NORP from January 1, 1982.

2. Alberta Oil Royalty Factors

Date	Par[1,2] Price ($/m^3)	Select Price ($/m^3)	K Factors Old	K Factors New[3]	K Factors NORP[3]
Jan. 1975	42.85	29.64	1.9390	0.560	
July 1975	52.29	29.64	1.7350	0.614	
July 1976	58.90	29.64	1.6096	0.5960	
Jan. 1977	63.31	29.64	1.5985	0.6154	
July 1977	69.60	29.64	1.5701	0.6262	
Jan. 1978	75.89	29.64	1.5452	0.6311	
July 1978	82.18	29.64	1.5178	0.6303	
July 1979	88.48	29.64	1.4962	0.6283	
Jan. 1980	94.77	29.64	1.4786	0.6283	
Aug. 1980	107.36	29.64	1.4518	0.6268	
Jan. 1981	113.65	29.64	1.4413	0.6261	
July 1981	119.94	29.64	1.4323	0.6256	
Oct. 1981	133.72	29.64	1.420102	0.626919	
Jan. 1982	147.88	29.64	1.406821	0.625769	0.620338
Apr. 1982	147.88	40.90	1.076837	0.615256	0.615552
July 1982	162.04	40.90	1.076840	0.615369	0.615480
Jan. 1983	187.21	40.90	1.077010	0.615385	0.615523
July 1983	187.21	40.90	1.077010	N/A	0.615385
June 1985	231.25	40.90	1.076923	0.615385	N/A
Aug. 1985	231.25	40.90	1.007692	0.546154	N/A
Nov. 1985	231.25	40.90	1.007692	0.546154	N/A
Feb. 1986	180.90	40.90	1.007692	0.546154	N/A
Mar. 1986	155.75	40.90	1.007692	0.546154	N/A
Apr. 1986	120.00	40.90	1.007692	0.546154	N/A

Notes:

1. For the period July 1, 1982, to June 30, 1983, the new oil par price was set as follows:

	New Oil Par Price ($/m^3)
July 1, 1982, to December 31, 1982	190.50
January 1, 1983, to June 30, 1983	195.50

2. For the period January 1, 1982, to May 31, 1985, the NORP par price was set as follows:

	NORP Par Price ($/m^3)
January 1, 1982, to June 30, 1982	278.00
July 1, 1982, to December 31, 1982	260.95
January 1, 1983, to June 30, 1983	271.20
July 1, 1983, to May 31, 1985	246.10

3. Effective July 1, 1983, the definition of NORP oil was expanded to include all post 1973 oil discoveries. Effective June 1, 1985, the NORP oil category was renamed new oil, which corresponds to the pre-1982 new oil definition.

3. Previous Gas Royalty Formulae

F ($¢/10^3m^3$)	Old Gas (as %)	New Gas (as %)
less than 923	22	22
923 to 994	$\frac{20306 + 25\ (F-923)}{F}$	$\frac{20306 + 24\ (F-923)}{F}$
994 to 1065	$\frac{22081 + 30\ (F-994)}{F}$	$\frac{22010 + 26\ (F-994)}{F}$
1065 to 1136	$\frac{24211 + 35\ (F-1065)}{F}$	$\frac{23856 + 28\ (F-1065)}{F}$
1136 to 1207	$\frac{26696 + 40\ (F-1136)}{F}$	$\frac{25844 + 30\ (F-1136)}{F}$
1207 to 1278	$\frac{29536 + 45\ (F-1207)}{F}$	$\frac{27974 + 33\ (F-1207)}{F}$
over 1278	$\frac{32731 + 50\ (F-1278)}{F}$	$\frac{30317 + 35\ (F-1278)}{F}$

The previous low productivity formula was identical to the current formula except that the break point was 7000 cubic metres per day. Thus, the number 16.9 in the current formula would be replaced by 7 to derive the previous formula.

4. Geophysical Incentive System

Incentives were offered under the Geophysical Incentive System (GIS) for seismic surveys commenced within specified periods of time, from January 1, 1975, to July 31, 1985. The most recent provisions relating to this program are found in Alberta Regulation 138/84. Under this regulation, seismic surveys which commenced between April 1, 1984, and July 31, 1985, were eligible for a grant which varied from $150 to $4,000 per kilometre of minimum subsurface coverage depending on the location of the survey within Alberta, the type of equipment used, and the nature of the recording method employed. Application for the grant could be made within 150 days after the completion of the survey.

Prior to April 1, 1984, incentive credits instead of grants were earned under the GIS. As under the EDIS, these incentive credits could be used to offset bonus payments, rentals, Crown royalties and freehold mineral taxes otherwise payable prior to January 1, 1991, or could be refunded, in cash, at the option of the recipient. It was also required that all data resulting from the survey had to be made public after an initial five-year confidentiality period.

5. Exploratory Drilling Incentive System

Incentives were provided under the Exploratory Drilling Incentive System (EDIS) from August 1, 1972, to July 31, 1985. The most recent provisions relating to this program are found in Alberta Regulation 137/84. Under this regulation, an oil or gas well may qualify as an incentive exploratory well if either drilling or deepening commenced between April 1, 1984, and July 31, 1985. In order to receive certification, a well had to satisfy certain criteria concerning its location, the proximity of other wells, and the depth of drilling or deepening. The EDIS was replaced, effective August 1, 1985, with new oil and gas royalty holiday programs (see Chapter IV, section E).

The incentives offered under the EDIS took two forms. First, royalties and freehold mineral taxes payable on production from the incentive well (or its twin well) were waived for a specified initial period of production. Under Alberta Regulation 137/84, the period of royalty exemption was five years for an incentive exploratory oil well and one year for an incentive exploratory gas well. It was also provided, however, that the maximum value of royalty relief in respect of an incentive exploratory well was not to exceed $2 million.

The second form of incentive under the EDIS was a credit for each metre of qualified drilling in the province. The rate of credit was dependent on the depth of each qualifying interval. The credit could be applied against bonus payments, rentals, Crown royalties or freehold mineral taxes payable prior to January 1, 1991, or could be refunded, in cash, at the option of the recipient.

6. Oil Royalty Exemption System

The Oil Royalty Exemption System (ORES) was applicable to exploratory oil wells which did not qualify for an incentive under the EDIS. The ORES was in effect from April 1, 1984, to July 31, 1985. Eligible wells under the ORES were allowed a one-year royalty holiday to a maximum of $1 million per well. Such wells included new field wildcats, new pool wildcats, deeper pool tests and outposts. (See Oil Royalty Exemption Regulation 139/84.)

7. Royalty Tax Credit

For corporate taxation years beginning between January 1, 1984, and March 31, 1986, the Alberta royalty tax credit was equal to 50 percent of Alberta Crown royalties payable to a maximum of $2 million; between September 1, 1981, and December 31, 1983, 75 percent of royalties payable to a maximum of $4 million.

C. SASKATCHEWAN FISCAL CHANGES

1. Pre-June 1, 1985, Oil Royalty Classification

From August 1, 1983, to May 31, 1985, three classes of Crown oil production in Saskatchewan existed: old oil, NORP oil and EOR oil. NORP oil was oil that is currently defined as new oil. Prior to August 1, 1983, four classes of Crown oil production existed: old oil, new oil, NORP oil and EOR oil. New oil was from wells completed between 1974 and 1980, and incremental production from secondary recovery projects which commenced operation after 1973 and tertiary recovery projects which commenced operation between 1974 and 1980. NORP oil was from wells completed after 1980.

2. Previous Oil Royalty Factor Values

Royalty factor values for oil from both Crown and freehold land have changed to reflect both pricing and policy changes. The values for the period January 1, 1983, to July 31, 1983, were as follows:

	OLD	NEW	NORP
C	0.6016	0.6016	0.5118
K	51.8	51.8	44.1
X	1115	1115	950
DMF	1	0.778	1
AAF-light	1	1	1
-heavy	N/A	0.9	0.8
PTF-Crown	0	0	0
-Crown acquired:	existing lease rate	existing lease rate	existing lease rate
-freehold	6.9	8.3	11.0

Oil royalty factor values for the period August 1, 1983, to May 31, 1985, were the same as the current values; the NORP oil values of the previous period corresponding to the current new oil values.

3. Pre-July 1, 1985, Natural Gas Royalty Regime

Prior to July 1, 1985, all natural gas produced in Saskatchewan was subject to a flat rate royalty. Thus, it was neither price nor productivity sensitive. Old and new gas prices, however, were sensitive to well productivity. In general, the royalty rate increased by 20 percent of any Alberta border price increases. Previous royalty rates were as follows:

	Natural Gas Royalty Rate ($/10^{3}m^3)
February 1, 1983, to July 31, 1983	3.55
August 1, 1983, to January 31, 1984	5.32
February 1, 1984, to July 31, 1984	6.51
August 1, 1984, to June 30, 1985	6.57

D. BRITISH COLUMBIA FISCAL CHANGES

The Government of British Columbia restructured its royalty regime applicable to natural gas, effective July 1, 1985. The new regime is sensitive to the age, depth, location and productivity of a well, and to the price of gas (see Chapter VI, section B).

Prior to July 1, 1985, old gas was produced through a well in a pool from which there was production prior to November 14, 1973. New gas was from pools which began production subsequent to that date. In either case, gas which was used in drilling for or production of oil and gas, which was lost by no fault of the producer and for which he received no compensation, or which was sold to the British Columbia Petroleum Corporation (BCPC) under a contract that stipulated that the BCPC would pay all provincial royalties, was exempt from provincial royalties. (See Petroleum and Natural Gas Royalty Regulation 549/78.)

The latter stipulation was of particular importance since the vast majority of natural gas produced in British Columbia was sold to the BCPC under such contracts and was, therefore, exempt from direct royalty. The BCPC, acting as intermediary, sold the gas to Westcoast Transmission and the provincial revenue share was derived from the difference between the price paid to producers and the price received from Westcoast. The policy intent was to make British Columbia netbacks comparable to those in Alberta (less transmission costs which were borne by Westcoast, not by the producer). In addition, freehold land from which gas was sold to the BCPC was exempt from the Mineral Land Tax.

For natural gas not sold to the BCPC, a royalty was imposed based on price and the date the pool was defined. The quantity of this gas produced in British Columbia was insignificant, however; the province earned only about $1,000 per month from this source. Field condensates from natural gas were subject to oil royalty rates.

Natural gas by-products (i.e., propane, butane, pentanes plus and sulphur) produced at a processing plant and not sold to the BCPC, were subject to a 50 percent royalty rate if extracted from old gas and a 30 percent rate if extracted from new gas. Where the by-products were sold to the BCPC, the producer received 12 1/2 percent of their sale value. Where a supplement was payable on extracted by-products sold to the BCPC, a 30 percent royalty was applied to the supplement which was paid directly to the producer.

E. FRONTIER LANDS FISCAL CHANGES

As mentioned above, the federal government announced a new frontier fiscal regime on October 30, 1985. The legislative framework for the frontier regime will be contained in the Canada Petroleum Resources Act which will replace the Canada Oil and Gas Act (COGA).

Two royalties were applicable to production from the frontier lands under the COGA: a basic royalty of 10 percent of gross revenue from production; and a Progressive Incremental Royalty (PIR) equal to 40 percent of net profit. Net profit equalled gross revenue minus operating costs, the basic royalty, the PGRT, an income tax abatement, a capital cost allowance and an allowed 25 percent return on capital. A three-year PIR holiday was available for projects in which the discovery well commenced drilling before February 2, 1981, and which qualified to be declared a significant discovery before January 1, 1983.

The Crown was also to receive a 25 percent share of all production from the frontier lands under the COGA. This Crown Share Interest was to be converted from a carried interest to a working interest after completion of the exploration phase of an Exploration Agreement. In turn, the Crown contributed 25 percent of post-1980 exploration expenses in frontier areas in the form of PIP grants (see Chapter III for a discussion of the PIP).

For pre-1981 expenditures on a field declared significant by 1983 and which was first drilled before 1981, an ex gratia payment was to be made in lieu of a PIP grant. The payment was to be made out of the Crown share of the net proceeds of production. This payment was to equal one-quarter of 250 percent of exploration expenses incurred before 1981 grossed up by 1.25 percent per month to the end of 1980. The gross-ups were intended to account for the impacts of interest and inflation, as well as to provide some compensation for the risk taken by the initial investor.

APPENDIX II

SAMPLE TAX CALCULATIONS

A. CORPORATE INCOME TAX

1. Assumptions:
   - i) Gross resource income = $300.00
   - ii) Operating costs = $40.00
   - iii) Crown royalty = $90.00
   - iv) Capital expenditures: CEE = $50.00; CDE = $25.00; Well equipment = $25.00
   - v) Post PIP regime

2. Tax Calculation: 1986

	Federal	Provincial
Gross Resource Income	$300.00	$300.00
Less: Operating Costs	40.00	40.00
CCA on class 10 at 30% (1)	3.49	3.49
= Resource Profits for Resource Allowance	256.51	256.51
Less: Resource Allowance	64.13	64.13
Royalty Tax Deduction	-	25.87
CDE at 30%	7.50	7.50
CEE at 100%	50.00	50.00
= Net Resource Income	$134.88	$109.01
Tax Otherwise Payable (2)	$ 50.98	$ 11.99
Less: ITC at 7% (3)	1.75	-
Tax Payable	$ 49.23	$ 11.99

Notes: 1. CCA on class 10(j) well equipment is calculated as follows:

Cost Base	$25.00
Less: ITC at 7%	1.75
= Adjusted Cost Base	23.25
CCA at 30%	$ 6.98
Half-year convention (divided by 2)	$ 3.49

2. Federal tax rate equals 37.8 percent; provincial tax rate equals 11 percent.

3. Other tax credits are also available such as the federal exploration tax credit and the Alberta royalty tax credit.

B. PETROLEUM AND GAS REVENUE TAX

1. Assumptions

It is assumed that a property is held by two taxpayers; a working interest and a royalty interest. The working interest pays a 10 percent resource royalty to the royalty interest. Resource income from the property is assumed to equal $300: $270 of production revenue accruing to the working interest and $30 of resource royalty income. Operating costs associated with production equal $40.

2. PGRT Calculation: 1986

	Working Interest	Resource Royalty Interest	Aggregate Calculation
Gross Revenue	$300.00	$ 30.00	$300.00
Less: Operating Costs	40.00	--	40.00
= Net Operating Revenue	$260.00	$ 30.00	$260.00
Less: Resource Royalty	30.00	--	--
Resource Allowance	65.00	--	65.00
= Revenue Subject to PGRT	$165.00	$ 30.00	$195.00
PGRT at 13 1/3%	$ 22.00	$ 4.00	$ 26.00

Notes:

1. After 1985, where a property has more than one interest holder, both the working interest holders and the royalty interest holders must remit their share of the PGRT to the government. In the above example, the working interest would, therefore, remit $22.00 and the royalty interest would remit $4.00. An exception to this rule exists where the resource royalty holder is a non-resident who is not carrying on an oil and gas business in Canada. In this case, the working interest must deduct the full amount of PGRT payable by himself and the non-resident, and remit it directly to the government. The working interest would, therefore, remit $26 of PGRT to the federal government and $26 of royalty income to the non-resident, resource royalty interest, in the above example.
2. The working interest pays PGRT equal to 8.5 percent of his net operating revenue, whereas the resource royalty interest pays 13 1/3 percent. Total PGRT collection is 10 percent of net operating revenue.
3. A small producers' credit is also available to reduce a corporation's PGRT otherwise payable on production income. Individuals, and corporations which do not claim the small producers' credit are eligible for a $10,000 PGRT deduction in calculating their production and royalty income.

APPENDIX III
AN EVALUATION OF ALTERNATIVE INVESTMENTS

As is evident from this review of fiscal systems in Canada, investments in crude oil and natural gas exploration and development, and capital expenditures on assets used in conventional production, tertiary oil recovery, oil sands mining, heavy crude oil upgrading, and oil refining and natural gas processing are each treated differently for tax and, in certain cases, for royalty purposes. In order to provide a better understanding of the interaction of the tax and royalty provisions, and their relative impacts on alternative investment opportunities, the following two measures are discussed in this section:

i) the after-tax cost of capital; and
ii) the B-index.

The after-tax cost of capital measures the cost of an investment, in present value terms, after all applicable tax and royalty implications of that investment have been taken into account. The after-tax cost calculation is composed of two parts. First, the adjusted cost base of the asset is determined by reducing its initial capital cost by the amount of any provincial incentives, federal grants or tax credits that may be applicable. The adjusted cost base is then written off at the rate allowed by legislation and the tax value of the write-off is determined. Depletion, where applicable, is calculated on the adjusted cost base, but does not itself reduce the cost base. Rather, depletion increases the amount of write-off that would otherwise be available. The after-tax cost of an asset equals the difference between its adjusted cost base and the tax value of the allowed write-off.

Calculations based on $100 of investment in exploration, development and various capital assets are provided in the following table for both taxpaying and non-taxpaying corporations. In general, only the income tax impacts of an investment are considered.

The adjusted federal corporate tax rate of 37.8 percent is used for upstream investments while a 31.5 percent rate is used for expenditures on downstream (i.e., Class 29) assets. The provincial corporate income tax rate is assumed to be 11 percent for upstream activities and 5 percent for downstream activities. The capital write-off rate is expressed in present value terms using a 10 percent rate of discount so as to incorporate the tax savings which would be realized in future years. The half-year rule applicable to capital cost allowances is employed. The relative position of the resource allowance in the income tax calculation is also taken into account. Earned depletion is included where applicable. A 10 percent investment tax credit is applied to all eligible tangible capital assets (Class 10(1) mining social assets do not qualify) except in Atlantic Canada where a 20 percent rate is used. The credit is assumed refundable at a 20 percent rate for non-taxpayers. The exploration tax credit is assumed applicable to frontier exploration expenditures.

A criticism of the after-tax cost measure is that its value varies inversely with changes in the corporate income tax rate. Assuming a capital expenditure is deductible in calculating income tax, the higher the corporate income tax rate, the lower the after-tax cost of the expenditure. It seems unlikely, however, that a higher tax rate would generally be regarded as an incentive to invest.

For this reason, the B-index has been proposed as an alternative measure of the relative attractiveness of different investment opportunities. The B-index yields the present value of before-tax income necessary to cover the cost of an initial investment and to pay all applicable taxes. It addresses the anomaly of the after-tax cost of capital. Unlike the after-tax cost measure, the B-index can also take account of all applicable royalties and taxes in determining the cost-covering amount of before-tax and royalty income, if so desired. The after-tax cost is restricted to those taxes and royalties which allow for the deductibility of exploration, development or capital expenditures.

The B-index calculations for taxpayers provided in the following table include only income tax impacts on investment. They are derived, based on the after-tax cost of capital, according to the following formula:

$$\text{B-index} = \frac{\text{ATC}}{1-t(1-a)}$$

where: ATC is the after-tax cost of capital;
t is the corporate income tax rate; and
a is the resource allowance rate.

A corresponding B-index value for non-taxpayers does not exist since, by definition, a non-taxpayer's taxable income is non-positive. (For a discussion of the B-index, see D.G. McFetridge and J.P. Warda, Canadian R&D Incentives: Their Adequacy and Impact (Toronto: Canadian Tax Foundation, 1983).)

When applying the after-tax cost or B-index measures to evaluate alternative investments, it is important to include:

i) all taxes and royalties which allow for the deductibility of a particular expenditure in calculating after-tax costs; and
ii) all taxes and royalties which apply to income resulting from a particular investment in calculating the B-index, regardless of whether or not the expenditures are deductible for tax and royalty purposes.

Relative Value of Alternative Investments: 1986

($100 of Investment)

	After-Tax Cost		B-Index
	Taxpayer	Non-Taxpayer	Taxpayer
		($)	
Exploration - Frontier[1,2,3]	38	63	60
- Provincial[1,3]	51	70	80
Development - General[1,3]	60	91	95
- Tertiary[1,3,4]	43	91	68
Class 10(j) - General	64	98	101
- Atlantic Provinces	57	96	90
- Tertiary[1,4]	49	98	77
Class 10(k)[4]	49	98	77
Class 10(l)	71	98	112
Class 10(m)	64	98	101
Class 10(u)[4]	49	98	77
Class 28[4,5]	49	98	77
Class 29	67	98	106

Notes:
1. Post PIP regime. (See Chapter III for a discussion of the PIP.)
2. Assumes the 25% ETC is available for the total $100 of initial investment. The ETC is refundable at a 40% rate and reduces the capital base of the exploration expenditures when claimed or refunded.
3. Non-taxpayers are assumed to be able to use the PGRT offset for exploration and development expenditures. (See Chapter II for a discussion of the PGRT.)
4. Eligible for earned depletion at a 33 1/3% rate. Assumes 10(k) assets are processing assets.
5. In practice, Class 28 assets are usually written off at the standard 30% declining balance rate before income is produced. Hence, the accelerated allowance is not significant, provided the company is otherwise taxable, and, therefore, is not included in the calculations.

APPENDIX IV

CONVERSION TABLE

To convert	To	Multiply by
cubic metre	barrel	6.292871
barrel	cubic metre	0.158910
tonne	cubic metre	1.180384
million BTU	thousand cubic feet	1.000000
gigajoule	thousand cubic feet	0.932030
thousand cubic feet	thousand cubic metres	0.028328
gigajoule	thousand cubic metres	0.026402
$/cubic metre	$/barrel	0.158910
$/barrel	$/cubic metre	6.292871
$/tonne	$/cubic metre	0.847182
$/million BTU	$/thousand cubic feet	1.000000
$/gigajoule	$/thousand cubic feet	1.072927
$/thousand cubic feet	$/thousand cubic metres	35.300962
$/gigajoule	$/thousand cubic metres	37.875355

Notes: 1. These conversion factors are calculated at standard temperature and pressure.
2. The conversion of million BTU to thousand cubic feet is based on the heat content of wet gas.

APPENDIX V

GLOSSARY OF ACRONYMS

AENR: Alberta Energy and Natural Resources, a department of the provincial government

APIP: Alberta Petroleum Incentives Program, a provincial incentives program modelled after the federal PIP

BCPC: British Columbia Petroleum Corporation, a provincial Crown corporation

CCA: capital cost allowance, a deduction from income in respect of depreciation of tangible capital assets

CCPC: Canadian controlled private corporation

CDE: Canadian development expense, a deduction from income in respect of development activity

CEDOE: Canadian exploration and development overhead expense, a deduction from income in respect of overhead costs relating to exploration and development activities

CEE: Canadian exploration expense, a deduction from income in respect of exploration activity

COGA: Canada Oil and Gas Act

COGPE: Canadian oil and gas property expense, a deduction from income in respect of the acquisition of a Canadian resource property

COOP: Conventional Old Oil Price

COR/CS: Canadian Ownership Rate/Control Status, the rate which determines eligibility for PIP grants

COSC: Canadian Ownership Special Charge, a former charge on crude oil, natural gas and gas liquids

CPRA: Canada Petroleum Resources Act

EDIS: Exploratory Drilling Incentive System, a former incentive program for exploratory wells in Alberta

EOR: enhanced oil recovery, the use of secondary and tertiary recovery techniques to increase the amount of petroleum recoverable from a reservoir

ETC: exploration tax credit, a credit in respect of eligible exploration expenditures on any well in Canada costing in excess of $5 million

GCA: gas cost allowance, a reduction in gas royalties in Alberta, Saskatchewan, British Columbia and Nova Scotia in respect of gas processing fees

GEO-3: geological, geochemical and geophysical expenses, expenses incurred prior to the drilling of an exploration well

GIS: Geophysical Incentive System, a former incentive program for seismic surveys conducted in Alberta

GORR: gross over-riding royalty, a royalty interest in gross revenue from the production of oil or gas

IORT: Incremental Oil Revenue Tax, a former tax on the difference between the selling price and the NEP base price for old oil

IRC: investment royalty credit, a credit earned on frontier exploration well costs of up to $5 million per well, and applicable against federal royalties otherwise payable within a region in the frontier lands

IRRT: Incremental Resource Royalty Tax, a former tax on royalty revenues that result from the selling price exceeding the NEP base price for old oil

ITA: Income Tax Act

ITC: investment tax credit, a credit against federal corporate income taxes otherwise payable, earned on eligible capital expenditures

ITR: Income Tax Regulations

LNG: liquified natural gas

LPG: liquified petroleum gas, by-products of natural gas processing: propane and butane

LPWA: low productivity well allowance, a reduction in IORT related to low productivity wells

M&P: manufacturing and processing activities

NEB: National Energy Board, a federal regulatory body

NEP: National Energy Program, 1980 and NEP Update, 1982, federal programs of price determination, revenue sharing and Canadianization

NGGLT: Natural Gas and Gas Liquids Tax, a former tax on marketable pipeline gas in Canada

NGL: natural gas liquids, by-products of natural gas processing: ethane, propane and butane

NORP: New Oil Reference Price

ORES: Oil Royalty Exemption System, a former incentive program for exploratory wells in Alberta

PCC: Petroleum Compensation Charge, a former charge on domestic crude oil, the revenue from which was used to finance payments of NORP supplements and oil import compensation

PGRT: Petroleum and Gas Revenue Tax, a tax on revenue from oil and natural gas production

PIP: Petroleum Incentives Program, a federal program which provided grants in respect of exploration, development and some capital costs based on the level of Canadian ownership and control, and the geographical location of the investment

PIR: Progressive Incremental Royalty, a royalty on production in the frontier lands

RDIA: Regional Development Incentives Act

RIP: royalty incentive period, a royalty reduction in Manitoba based on the depth of a new oil well

SOOP: Special Old Oil Price

SPTC: share-purchase tax credit, a mechanism by which investment tax credits earned by corporations are allowed to be transferred to purchasers of new common equity

APPENDIX VI

FEDERAL LEGISLATIVE REFERENCE GUIDE

Name	Enabling Legislation	Dates Effective
Income Tax	Income Tax Act S.C. 1970-71-72, c. 68, as amended	- 1972
Petroleum and Gas Revenue Tax	Petroleum and Gas Revenue Tax Act S.C. 1980-81-82-83, c.68, Part IV, as amended	- January 1, 1981, to December 31, 1988
Incremental Oil Revenue Tax and Incremental Resource Royalty Tax	Petroleum and Gas Revenue Tax Act S.C. 1980-81-82-83, c.68, Part IV, as amended	- January 1, 1982, to December 31, 1984 - generally suspended for the period June 1, 1982, to December 31, 1984
Petroleum Compensation Charge	Energy Administration Act[1] S.C. 1980-81-82-83, c.114, as amended	- July 12, 1980, to May 31, 1985
Canadian Ownership Special Charge	Energy Administration Act[1] S.C. 1980-81-82-83, c.114, as amended	- May 1, 1981, to May 31, 1985
Natural Gas and Gas Liquids Tax	Excise Tax Act R.S.C. 1970, C. E-13, as amended	- November 1, 1980, to May 31, 1985
Oil Export Charge	Energy Administration Act[1] S.C. 1980-81-82-83, c.114, as amended	- May 1, 1979, to May 31, 1985
Royalties: Canada Lands	Canada Oil and Gas Act S.C. 1980-81-82-83, c. 81 Canada Petroleum Resources Act	- March 5, 1982 - to be enacted
Petroleum Incentives Program	Petroleum Incentives Program Act S.C. 1980-81-82-83, c.107, Part I	- June 30, 1982, to March 31, 1986 - grandfathering to December 31, 1987

Note: 1. The Energy Administration Act, S.C. 1980-81-82-83, c. 114 amends and renames the Petroleum Administration Act, S.C. 1974-75-76, c. 47, as amended.

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B. Federal Taxation and Incentive Schemes

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- Energy, Mines and Resources Canada, Press Releases and Information Letters.
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- Lewis and Thompson, Canadian Oil and Gas Statutes and Regulations, Butterworth and Co.
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C. Provincial Royalties, Taxes and Incentive Schemes

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- CCH Canadian Ltd., Provincial Tax Reporter.
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- AENR, Energy Statutes and Regulations, 1980.
- AENR, Freehold Mineral Rights Tax Act: Information Package, March 1983.
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